CANADA SOUTHERN PETROLEUM LTD.

1998 Annual Report
(Includes Report on Form 10-K)

CANADA SOUTHERN PETROLEUM LTD.

TO OUR SHAREHOLDERS:

Those of you who have climbed hills and mountains will be familiar with the feeling of expecting to reach the top, only to find another steep slope. The year 1998 gave most of us in the oil and gas industry the same feeling. Weaker oil prices were anticipated because of lower demand and oversupply, but the decline was more severe and lasted longer than anyone expected. In addition, the predictions for gas prices turned out to be overly optimistic because of the mild winter throughout most of North America. Fortunately, increased pipeline capacity between Canada and the U.S. has diminished the differential between U.S. and Canadian gas prices.

In anticipation of the lower oil prices and the Company's financial commitments over the next two years, the Company decided to sell certain of its producing properties, either because of their declining production or the nature of their reserves, in particular heavy oil. As a result, the Peejay and Atlee properties were sold for a total of $5.8 million and a gain of $1.4 million was realized.

While there will be a future revenue loss from these sales, the Company is now in a strong financial position to complete the Kotaneelee litigation and increase its inventory of new prospects. One benefit of lower oil and gas prices has been that the purchase of prospective leases is more affordable. Several leases have already been acquired through Crown sales at very attractive prices. Lease acquisitions will continue, if prices remain realistic. There will also be a modest amount of seismic and drilling where there is an expectation of short term benefits. However, full exploration and development of the Company's prospects will have to wait for better prices and a resolution of the Kotaneelee litigation.

As I mentioned in the 1997 annual report, it took nearly 30 years for the Kotaneelee gas field to be produced and it is incredible that the Company is still fighting to keep it in production and have it properly explored and developed. Late in 1997, two non-producing wells were abandoned and the Company was very disappointed and concerned that no attempt was made to recomplete one of the wells, the E-37 well. Consequently, the Company in 1998 attempted to amend its claim against its working interest partners to include a claim that the field was not being properly developed. Since the attempt to amend was unsuccessful, a separate claim is being made. The Company had made an effort to resolve the development issue without litigation in a manner that would have been satisfactory to all of the Kotaneelee participants. Unfortunately, the defendants failed to respond and the separate claim was necessary to preserve the Company's rights.

It is estimated that the defendants will take most of 1999 to complete their defense. The length of the trial has been frustrating and disappointing, but gas production from the field continues to be excellent. The payout of the carried interest account has been delayed due to the cost of remedial work done on the B-38 well, but the work has had a very positive impact on production. As a result of uphole trouble, it was necessary for remedial work to be performed. The early indications are that the B-38 well is capable of producing at rates at least comparable to the I-48 well. In the first three months after the B-38 well was put back on production, production increased over 20 million cubic feet per day. It is obvious what the economic benefit to all of the Kotaneelee participants would have been if this remedial work had been undertaken in a timely manner, and if there had been additional development wells.

For the year 1998, the Company's net loss was $2.7 million, or $.19 a share, compared to a net loss of $1.8 million, or $.12 per share, in 1997. The litigation costs ($2.3 million in 1998) of the Kotaneelee field continue to dominate the Company's operations and account for its continuing losses.

As you are probably aware, the Company has contested the amount of the carried interest account in the current litigation. As of December 31, 1998, the amount remaining to be recovered in the carried interest account as calculated by the Operator was $19 million (Company share - $5.7 million). Since the working interest owners' have not provided any information about their gas sales contracts, the Company is unable to calculate when the balance will be paid off. Based on current production rates and prices, and assuming no major capital expenditures, it is reasonable to expect that the Company should begin to receive its share of field revenues in the year 2000.

The Board of Directors would like to thank all of our shareholders for their patience and understanding with the Kotaneelee situation. It is unfortunate that the defendants' efforts directed toward the Kotaneelee litigation was not directed toward the exploitation and development of the field.

I would also like to personally thank the small group of dedicated individuals who have kept the Company going through these difficult and frustrating times. This is especially true for those who have been involved in the litigation who have made many personal sacrifices to the benefit of the Company and its shareholders.

Respectfully submitted,

M. Anthony Ashton
President

Calgary, Alberta
April 22, 1999

SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-K

(Mark One)

[X] **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 1998

OR

[ ] **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 [NO FEE REQUIRED]**

For the transition period from ______________ to ______________

Commission file number 1-3793

CANADA SOUTHERN PETROLEUM LTD.

(Exact name of registrant as specified in its charter)

NOVA SCOTIA, CANADA	98-0085412
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification No.)
Suite 1410, One Palliser Square 125 Ninth Avenue, S.E. Calgary, Alberta CANADA	T2G OP6
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (403) 269-7741

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Limited Voting Shares, $1 (Canadian) per share	Pacific Exchange, Inc. Boston Stock Exchange Toronto Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

(Title of Class)

Limited Voting Shares, $1 (Canadian) per share NASDAQ SmallCap Market

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☒ Yes ☐ No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K §229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

The aggregate market value of the voting stock held by non-affiliates of the registrant was approximately U.S. $67,501,000 at March 15, 1999.

(APPLICABLE ONLY TO CORPORATE REGISTRANTS)

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.

Limited Voting Shares, par value $1.00 (Canadian) per share, 14,234,740 shares outstanding as of March 15, 1999.

DOCUMENTS INCORPORATED BY REFERENCE

Proxy Statement of Canada Southern Petroleum Ltd. related to the Annual Meeting of Shareholders for the year ended December 31, 1998, which is incorporated into Part III of this Form 10-K.

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Unless otherwise indicated, all dollar figures set forth are expressed in Canadian currency. The exchange rate at March 15, 1999 was $1.00 Canadian = U.S. $.6552.

PART I

Item 1. Business

The nature of Canada Southern Petroleum Ltd.'s (the "Company" or "Canada Southern") business is described at Item 1(c) herein, and a description of its principal oil and gas properties in Canada appears in Item 2 herein. For additional information regarding the development of the Company's business, see "Properties" and "Supplemental Information on Oil and Gas Activities".

(a) General Development of Business

Yukon Territory - The Kotaneelee Field

The Company's principal asset is a 30% carried interest in the Kotaneelee gas field located on Ex-Permit 1007 (31,888 gross acres or 9,566 net acres) in the extreme southeastern corner of the Yukon Territory. This partially developed field is connected to a major pipeline system. Two wells have been completed to date that are capable of an estimated output of in excess of 60 million cubic feet per day, the capacity of the field dehydration plant. At December 31, 1998, field production was approximately 60-65 million cubic feet ("mmcf") per day. The operator is Anderson Exploration Ltd., which acquired all of Columbia Gas Development of Canada Ltd.'s interests. See Item 3 - "Legal Proceedings" for a discussion of the Kotaneelee Litigation concerning this asset.

Production at Kotaneelee commenced in February 1991. According to government reports, total production in billion cubic feet ("bcf") from the Kotaneelee gas field since 1991 has been as follows:

Calendar Year	Production (bcf)
1991	8.1
1992	18.0
1993	17.5
1994	16.7
1995	15.7
1996	15.2
1997	14.4
1998	16.0
Total	121.6

At present, the Company does not receive any cash payments from production but is credited with 30% of the gross revenues until a like percent of the working interest costs, exclusive of any interest expense, are recovered by the operator. The Company will not receive any payment from production revenues until its share of the working interest costs are recovered. When the deferred costs are recovered, 30% of gross revenues (net of gross overriding royalties) less 30% of current working interest costs will be paid to the Company. Gross overriding royalties amount to 10% to the Canadian Federal government and 4.06% to certain individuals. The operator has reported to the Company development costs totaling approximately $95,849,000 and, of that amount, approximately $19,039,000 (Company share = $5,712,000) remained to be recovered at December 31, 1998. The Company has contested the amount of costs that have been charged to the carried interest account. It is estimated that the Company will not begin to receive proceeds from the Kotaneelee gas field before the year 2000, based upon a price of $1.28 per mcf (average 1998 price) and current production rates. The period before payment to the Company begins may be shorter or longer, depending on prevailing market conditions and the results of the Kotaneelee Litigation.

British Columbia Properties

The Company's major source of income has been from oil and gas fields in northeast British Columbia. These fields, developed in the 1950's and 1960's, produce revenue through both working and carried interest agreements. During November 1998, the major working interests in these fields were sold to Canadian Natural Resources Ltd. ("CNRL") for approximately $3.5 million.

In addition to the producing properties, since 1988 the Company has acquired a number of leases in northeast British Columbia by participating in British Columbia land sales. To date five wells have been drilled on the lands resulting in three oil discoveries and two dry holes. Currently, the Company is defining the prospects by geophysics. Work completed to date indicates that six of the prospects justify drilling. The Company estimates that the drilling costs (excluding completion costs) of the six prospects would be $1,625,000. However, as most of these wells would be wildcat wells (exploratory wells), the Company plans to reduce its risk by selling or farming out part of its interest. The timing of the drilling is dependent on the availability of funds. The Company anticipates that its average net cost per well (assuming a farmout or sale) would be approximately $75,000, or a total of $525,000, for drilling and completion costs.

One prospect has been farmed out on a seismic option basis. If the farmee elects to drill a well, the Company will not be required to pay any of the drilling costs. In 1998, the Company acquired leases on two additional prospects.

In the Paradise area, one well that was drilled and completed as an oil well in 1997 proved to be non-commercial. Another oil well, which was drilled under a farmout arrangement, is currently suspended. An additional farmout well which was drilled in late 1997 has been plugged and abandoned.

The Company also has interests at Buick Creek, Wargen and Siphon. The Siphon and Wargen fields have new operators. As these properties are held under the carried interest agreements, the Company is not aware of any proposed exploration and development plans for these properties, but anticipates the change of operator will cause new work to be done.

Arctic Islands

As of December 31, 1998, the Company held working interests in 45,100 gross acres (1,817 net acres) and carried interests in 131,730 gross acres (37,180 net acres) in the Sverdrup Basin, located in the Arctic Islands. The Hecla, Whitefish, Drake Point, Roche Point, Kristoffer, Romulus and Bent Horn fields have been designated significant discovery lands ("SDL") by the Federal Government. The Company's interests in the SDL's have been retained pending development.

Panarctic Oils Ltd. ("Panarctic"), the operator, received Federal government regulatory approvals for a pilot project to move shipments of crude oil from the Bent Horn field by tanker through the Northwest Passage to southern Canada in 1985. Through December 31, 1996, approximately 2.7 million barrels of Bent Horn crude had been sold with deliveries being made at northern Canadian and European markets as well as the eastern seaboard market. In 1996, the operator decided to shut down production from the field and dismantle the production facilities because of economic uncertainties. The Company has a 5% carried interest in the area which has not yet reached payout status. The timing of any payout is uncertain.

Northwest Territories Properties

The Company has a 45% carried interest in the Northwest Territories in the Celibeta field designated as Significant Discovery Lands ("SDL") by the Federal Government (1,594 gross acres and 717 net acres). The gas field is presently shut-in.

Alberta

In 1994, the Company purchased a 5% working interest in the Kitscoty heavy oil field and the related facilities. Oil recovery from this field is being enhanced by steam injection.

In 1996, the Company purchased an additional 5% working interest in the Kitscoty field. Three more wells were drilled in 1996; two horizontal wells and one vertical well. All the wells encountered oil and were completed as oil wells. One well also discovered three potential gas zones which will be evaluated for future use as fuel for the steam generation needed to enhance the oil production. Scheduled remedial work programs have been postponed pending an increase in the current low netbacks on heavy oil. Additional work at the new Lloydminister heavy oil discovery at 16-2-51-2 W4M has also been postponed for this reason.

During 1997 and 1998, the Company participated in the exploration and development of a glauconite heavy oil project in the Atlee/Majestic area. A multitude of production problems occurred which caused numerous delays. Although the project was successful in developing substantial reserves, the prevailing low heavy oil prices made the economic return on this project less favorable than other Company projects. For this reason, the Company's interest was sold in November 1998 for $2.2 million.

The Company also acquired a 10-20% working interest in over 12,000 acres in four other areas of Alberta. These lands were purchased on the basis of seismic work which showed a number of promising prospects. Subsequently, additional seismic work has confirmed the potential of those prospects. One was drilled in 1997 and completed as a potential gas well. A second well was drilled in early 1998 and completed as an oil well.

In 1998, the Company purchased leases (100% interest) in an area prospective for both oil and gas. The leases are currently being evaluated with the intent of drilling in late 1999 or early 2000.

In Alberta, the Company currently has working interests ranging from 10% to 100% in a total of 1,920 gross (326 net) developed acres and 26,869 gross (8,448 net) undeveloped acres.

Saskatchewan

The Company has a 3.75% working interest in five sections in Saskatchewan. During 1997, three wells were drilled on the lands resulting in 2 dry holes and 1 shut-in gas well.

United States

Texas

In 1996 and 1997, the Company participated in the drilling of four wells in Texas which resulted in four potential oil wells. Because of low production rates and low oil prices, three of the wells have since been abandoned, leaving one producing oil well. During 1998, the costs of these wells totaling $489,000 were written off. Based on the technical results of these wells in which it has a relatively small interest, the Company commenced a new leasing program and acquired four leases (100% interest) on which it conducted a seismic program in 1998. Currently, plans are being made to test the first of several Chappel reef prospects on these leases in the second quarter of 1999.

California

During March 1998, the Company agreed to participate with two other companies in a heavy oil recovery project in California. The field is estimated to have approximately 12 million barrels of oil in place with only 13% of the oil recovered to date. The initial purchase price for a 90% (75% after payout) interest in the project is U.S. $200,000 (Company share 30% - U.S. $60,000). Capital expenditures were expected to be U.S. $600,000 to perform remedial work on the field and to complete a pilot stream flood program during the first year of the project (Company share U.S. $180,000). If the total amount of expenditures is less than U.S. $600,000, the participants' interests will be reduced proportionately to an amount which is not less than 10% (Company share – 3%). Because of the current low price of heavy oil, major development work on the project has been suspended pending an increase in oil prices. In addition, the Company also wrote off the carrying costs of the property in the amount of $196,000 during 1998.

(b) Financial Information about Industry Segments

Since the Company is primarily engaged in only one industry, oil and gas exploration and development, this item is not applicable to the Company. See Item 8 – "Financial Statements and Supplemental Data" for general financial information concerning the Company.

(c) (1) Narrative Description of the Business

The Company was incorporated in 1954 under the Canada Corporations Act. In 1979, it became subject to the Canadian Business Corporations Act and in 1980, was continued under the Nova Scotia Companies Act.

The Company is, either in its own right, or through other entities, engaged in the exploration for and development of properties containing or believed to contain recoverable oil and gas reserves and the sale of oil and gas from these properties. Although many of the properties in which the Company has interests are undeveloped, all properties with proved reserves are partially or fully developed. The Company's interests in exploratory ventures are on properties located in Alberta, British Columbia, Saskatchewan, the Northwest and Yukon Territories and the Arctic Islands in Canada and in the United States. The Company's principal asset is its 30% carried interest in the Kotaneelee field, a partially developed gas field (See Item 3 - "Legal Proceedings".) The Company also has interests in producing properties in British Columbia and Alberta.

Most of this acreage is covered by carried interest agreements, which provide that revenues are not payable to the Company until expenditures by the carrying partners have been recouped from production, and that operating decisions are made by the carrying partners. Generally, the Company may, at any time, as to each block or economic unit, elect to convert from a carried interest position to a working interest position by paying its share of the unrecouped expenditures for the unit (i.e., expenditures not recouped from production revenues). At December 31, 1998, the Company's share of unrecouped expenditures were as follows:

British Columbia:	
Ex-permit 149	$4,013,000
Yukon and Northwest Territories:	
Ex-permit 1007 (Kotaneelee)*	$5,712,000
Ex-permit 2713 (Celibeta)	$ 321,000

**See Item 3 - Legal Proceedings*

(i) Principal Products

The majority of the Company's interests are carried interests. The Company also participates in the production and sale of crude oil and natural gas derived from its working interests.

(ii) Status of Product or Segment

At present, some of the properties in which the Company has interests are undeveloped and/or nonproducing.

(iii) Raw Materials

Not applicable.

(iv) Patents, Licenses, Franchises and Concessions Held

Permits and concessions are important to the Company's operations, since they allow the search for and extraction of any crude oil and natural gas discovered on the areas covered. See the detailed schedule of properties under Item 2 - "Properties."

(v) Seasonality of Business

The Company's business is not seasonal, except that sales of natural gas peak during the winter heating season. Exploration and development activities are restricted in certain areas on a seasonal basis because extreme weather conditions affect transportation and the ability to pursue these activities.

(vi) Working Capital Items

Not applicable.

(vii) Customers

Substantially all oil production from the Company's properties for the current year was purchased by CNRL, the operator of the majority of the producing properties. Most of the natural gas produced from Company properties was sold by the operator, Petro Canada, to various gas marketers. The production from the Kotaneelee gas field is also being sold by the working interest partners who have not disclosed the purchasers.

(viii) Backlog

Not applicable.

(ix) Renegotiation of Profits or Termination of Contracts or Subcontracts at the Election of the Government

Not applicable.

(x) Competitive Conditions in the Business

The exploration for and production of oil and gas are highly competitive operations, both internally within the oil and gas industry and externally with producers of other types of energy. The ability to exploit a discovery of oil or gas is dependent upon considerations such as the ability to finance development costs, the availability of equipment, and the ability to overcome engineering and construction delays and difficulties. The Company must compete with companies which have substantially greater resources available to them. Because the majority of Company interests are in remote areas, operation of its properties is more difficult and costly than in more accessible areas.

Furthermore, competitive conditions may be substantially affected by various forms of energy legislation which may have been or may be proposed in the United States and Canada; however, it is not possible to predict the nature of any such legislation which may ultimately be adopted or its effects upon the future operations of the Company. For a further discussion of Canadian governmental regulation of the petroleum industry, see Item 1(d)(2) – “Risks Attendant to Foreign Operations”.

(xi) Research and Development

Not applicable.

(xii) Environmental Regulation

In the exploration for and development of natural resources, the Company is required to comply with significant environmental laws and regulations which add to the expense of those activities. The Company has not been required to spend significant sums to comply with clean up laws and regulations. Compliance by the Company with governmental provisions regulating the discharge of materials to the environment or otherwise relating to the protection of the environment are not expected to have a material effect on the capital expenditures, earnings or competitive position of the Company.

(xiii) Number of Persons Employed by Company

The Company currently has three full time employees, all of whom are located in Canada. The Company also relies to a great extent on consultants (approximately 10) for technical, legal, accounting and administrative services. The Company uses consultants because it is more cost effective than employing a larger full time staff.

(d) Financial Information about Foreign and Domestic Operations and Export Sales

(1) Revenues, Operating Losses and Identifiable Assets

Substantially all of the Company's operating assets and revenues are attributable to its operations in Canada. Operating losses are substantially attributable to the ongoing Kotaneelee litigation.

(2) Risks Attendant to Foreign Operations

The properties in which the Company has interests are located primarily in Canada and are subject to certain risks involved in the ownership and development of such foreign property interests. These risks include but are not limited to those of: nationalization; expropriation; confiscatory taxation; native rights; changes in foreign exchange controls; currency revaluation; burdensome royalty terms; export sales restrictions; limitations on the transfer of interests in exploration licenses; and other laws and regulations which may adversely affect the Company's properties, such as those providing for conversion, proration, curtailment, cessation or other forms of limiting or controlling production of, or exploration for, hydrocarbons. Thus, an investment in the Company represents an exposure to risks in addition to those inherent in petroleum exploratory ventures.

Governmental Regulation of the Canadian Oil and Natural Gas Industry

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government relating to land tenure, production, production facilities, pricing and marketing, royalties, environmental protection and other matters. Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry in Canada. All current legislation is a matter of public record and the Company is unable to predict whether any additional legislation or amendments may be enacted.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms from two years and on terms and conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated. The term of both Crown and freehold leases will generally continue as long as oil or natural gas is produced from the property.

Oil and natural gas rights on federal lands outside of the provinces is generally regulated by the Government of Canada unless authority has been delegated by agreement to the territorial government or the government of the province adjacent to the federal offshore area. In May 1993, the Canada Yukon Oil and Gas Accord was signed which allowed for the transfer to the Yukon of authority to administer and control oil and natural gas resources within that territory and for the establishment of an Oil and Gas Management Regime. The transfer has been completed and the lands are now administered by the Yukon Government.

Production and Production Facilities

The Governments of Canada, Alberta, British Columbia and Saskatchewan have enacted statutory provisions regulating the production of oil and natural gas. These regulations may restrict the maximum allowable production from a well based on reservoir engineering and/or conservation practices. The construction and operation of facilities to recover and process oil and natural gas are also subject to regulation.

Pricing and Marketing - Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Certain purchasers periodically advertise for volumes of oil they are prepared to purchase and the price being offered for such volumes. The price depends in part on oil quality, prices of competing fuels, distance to market and the value of refined products.

Pricing and Marketing - Natural Gas

In Canada, the price of natural gas is determined by negotiation between buyers and sellers, with the result that the market determines the price of natural gas. Natural gas exported from Canada is subject to regulation by the National Energy Board ("NEB") and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. As is the case with oil, natural gas exports for a term of less than two years must be made pursuant to an NEB order, or, in the case of exports for a longer duration, pursuant to an NEB license and Governor in Council approval.

The Governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Royalties and Incentives

The royalty regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands may also be subject to provincial taxes and regulations. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of the gross production, and the rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the product produced. The value of the gross production for royalty purposes may be based on a deemed value for the product rather than the actual value received by the interest holder.

From time to time the Governments of Canada, Alberta, British Columbia and Saskatchewan have established incentive programs which have included royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging natural gas and oil exploration or enhanced recovery projects. Incentives are intended to enhance the existing cash flow of the oil and natural gas industry and to improve the economics of finding and developing new and more costly oil and natural gas reserves. Oil royalty holidays for specific wells and royalty reductions reduce the amount of Crown royalties paid by the interest holder to the respective government. Tax credit programs provide a rebate on Crown royalties paid.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on spills, releases or emissions of various substances produced in association with certain oil and natural gas industry operations. An environmental assessment and review may be required prior to initiating exploration or development projects or undertaking significant changes to existing projects. In addition, legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of the appropriate authorities. A breach of such legislation may result in the imposition of fines or penalties. Federal environmental regulations also apply to the use and transport of certain restricted and prohibited substances. The Company is committed to meeting its responsibilities to protect the environment wherever it operates and believes that it is in material compliance with applicable environmental laws and regulations. The Company has not been required to spend significant sums to comply with clean up laws and regulations. Compliance by the Company with governmental provisions regulating the discharge of materials to the environment or otherwise relating to the protection of the environment are not expected to have a material effect on the capital expenditures, earnings or competitive position of the Company.

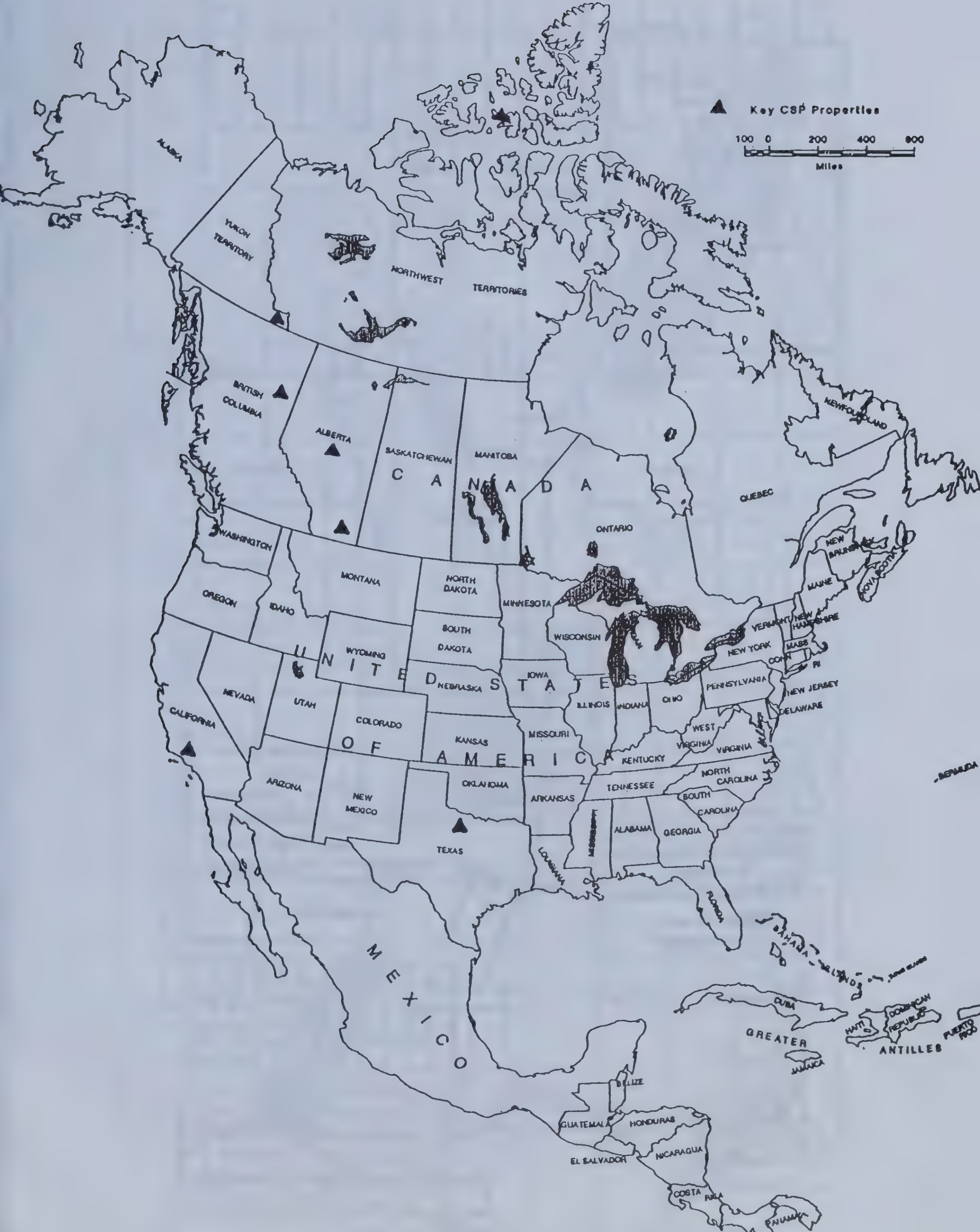
(3) Data which Are Not Indicative of Current or Future Operations

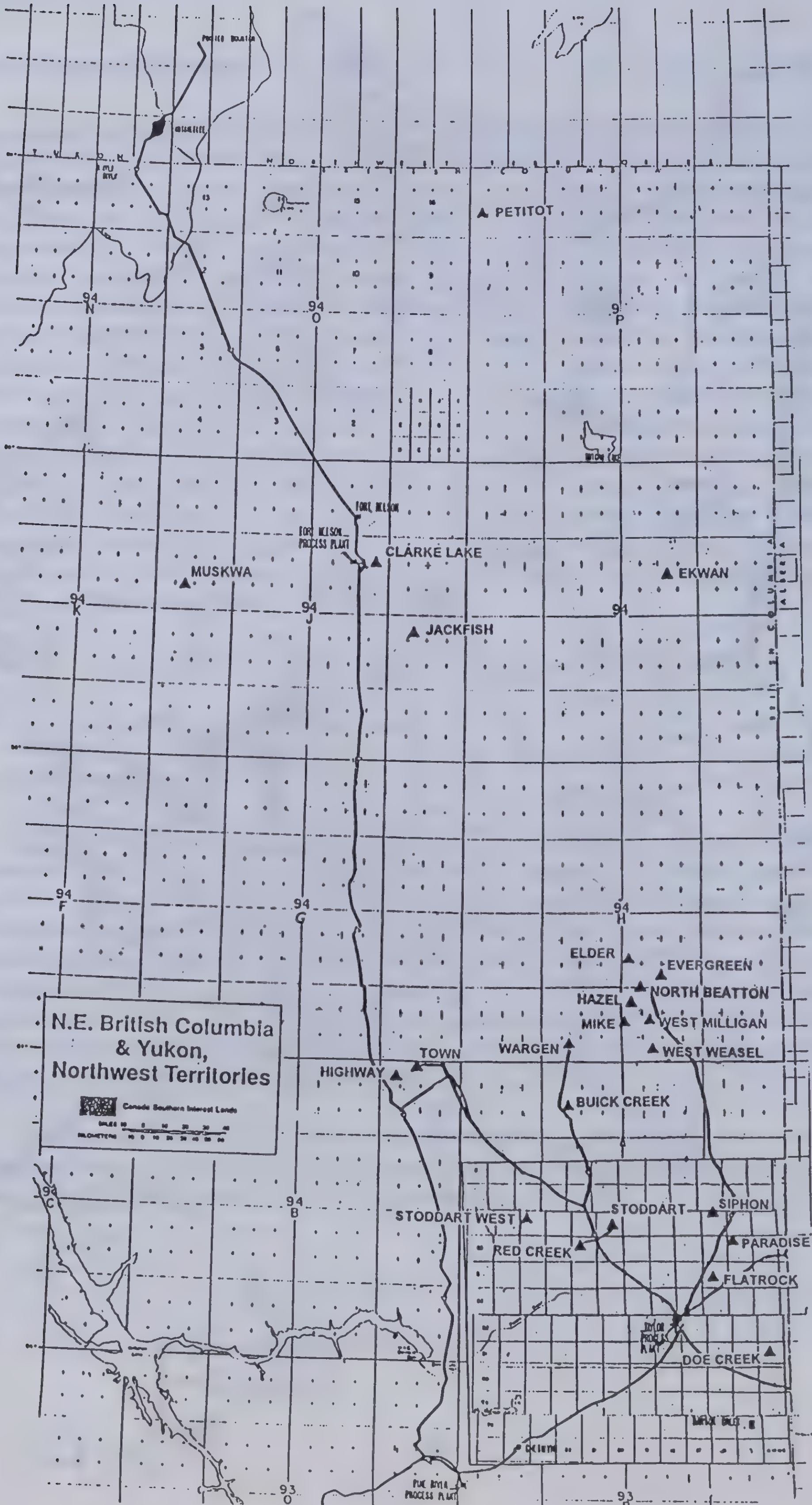
Not applicable.

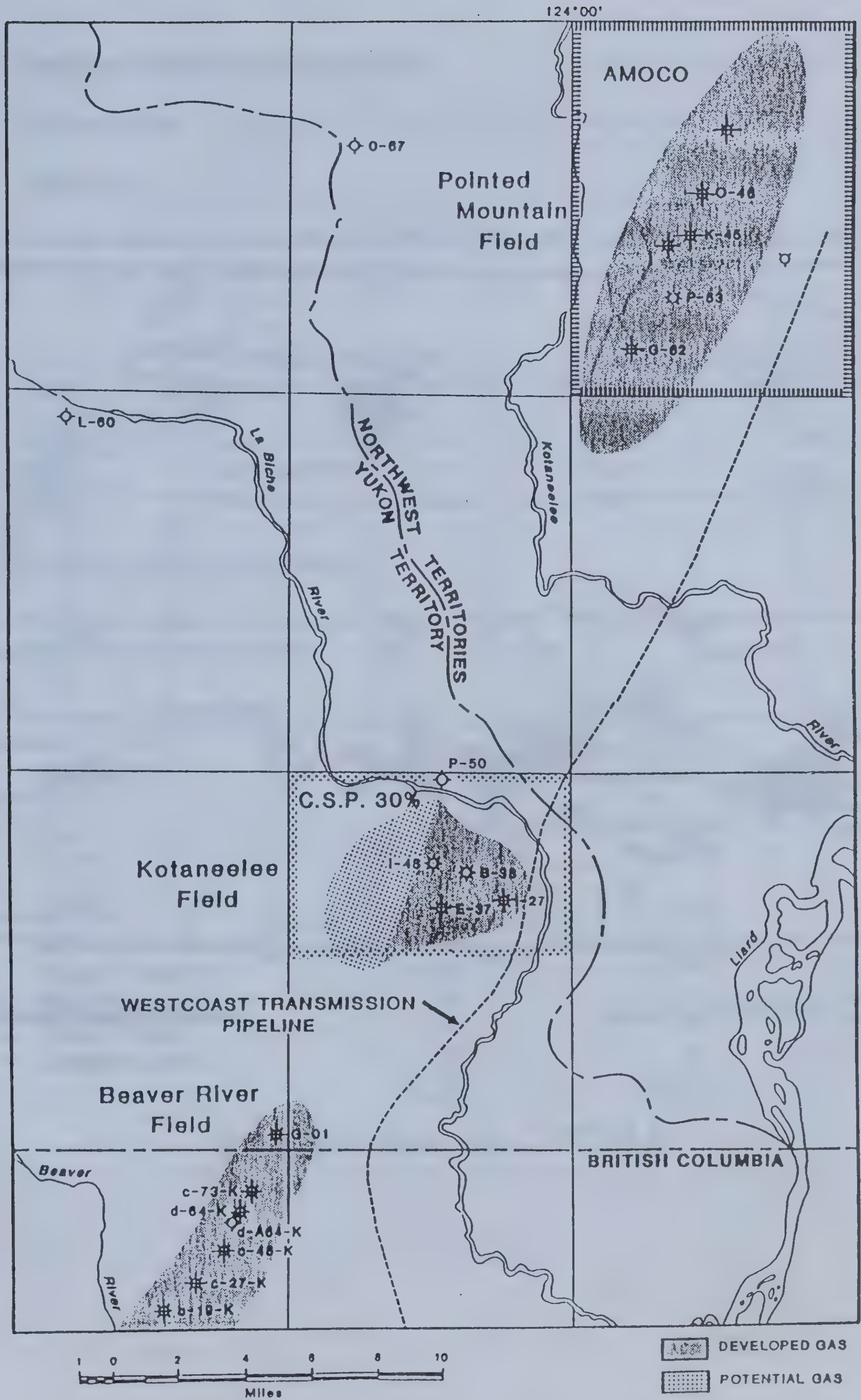
Item 2. Properties

(a) The principal asset of the Company is its 30% carried interest in the Kotaneelee field, a partially developed gas field in the Yukon Territory. See Item 3 - "Legal Proceedings." The Company also has interests in producing properties in British Columbia and Alberta and in several exploration prospects. The exploratory ventures are properties located in British Columbia, Alberta, Saskatchewan, the Yukon and Northwest Territories and the Arctic Islands in Canada and in the United States. Geophysical, geological and drilling work on the Company's properties is conducted by the operators under various agreements with the Company. The results of this work are reviewed by Company personnel and consultants retained by the Company.

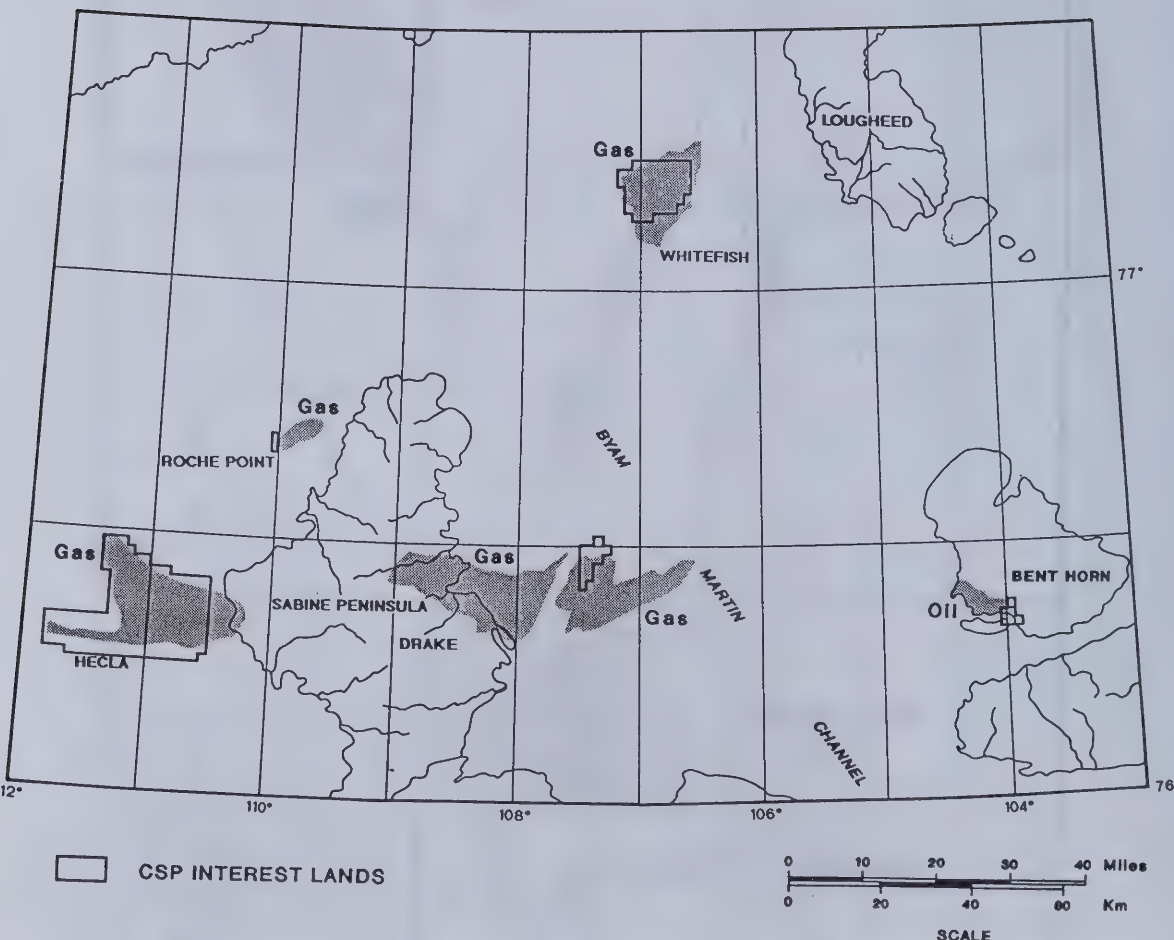
(b) (1) The information regarding reserves, costs of oil and gas activities, capitalized costs, discounted future net cash flows and results of operations is contained in Item 8 - "Financial Statements and Supplementary Data."


Key CSP Properties
100 0 200 400 800
Miles
ALASKA
YUKON TERRITORY
NORTHWEST TERRITORIES
BRITISH COLUMBIA
ALBERTA
SASKATCHEWAN
MANITOBA
C A N A D A
ONTARIO
QUEBEC
NEWFOUNDLAND
NEW BRUNSWICK
NOVA SCOTIA
WASHINGTON
OREGON
IDAHO
MONTANA
NORTH DAKOTA
SOUTH DAKOTA
MINNESOTA
WISCONSIN
WYOMING
U N I T E D S T A T E S
O F A M E R I C A
NEBRASKA
IOWA
NEVADA
UTAH
COLORADO
CALIFORNIA
KANSAS
MISSOURI
ILLINOIS
INDIANA
OHIO
PENNSYLVANIA
NEW YORK
VERMONT
NEW HAMPSHIRE
MAINE
MASS
CONN
RI
NEW JERSEY
DELAWARE
WEST VIRGINIA
VIRGINIA
KENTUCKY
ARIZONA
NEW MEXICO
OKLAHOMA
ARKANSAS
TENNESSEE
NORTH CAROLINA
SOUTH CAROLINA
MISSISSIPPI
ALABAMA
GEORGIA
TEXAS
LOUISIANA
FLORIDA
BERMUDA
M E X I C O
BAHAMA ISLANDS
CUBA
HAITI
DOMINICAN REPUBLIC
PUERTO RICO
GREATER ANTILLES
JAMAICA
BELIZE
GUATEMALA
HONDURAS
EL SALVADOR
NICARAGUA
COSTA RICA
PANAMA


N.E. British Columbia
& Yukon,
Northwest Territories
Canada Southern Interest Lands
PETITOT
94 N
94 O
94 P
FORT NELSON
FORT NELSON PROCESS PLANT
CLARKE LAKE
MUSKWA
EKWAN
94 K
94 J
JACKFISH
94 F
94 G
94 H
ELDER
EVERGREEN
NORTH BEATTON
HAZEL
MIKE
WEST MILLIGAN
WARGEN
WEST WEASEL
TOWN
HIGHWAY
BUICK CREEK
94 C
94 B
STODDART WEST
STODDART
SIPHON
PARADISE
RED CREEK
FLATROCK
DOE CREEK
93 O
93 P



KOTANEELEE FIELD



ARCTIC ISLAND FIELDS

(2) Reserves Reported to Other Agencies

Not applicable.

(3) Production

Average sales price per unit and average production cost for oil and gas produced during the periods shown below are as follows:

	Average Sales Price		Average Production Costs	
Year	Oil (per bbl)	Gas (per mcf)	Oil (per bbl)	Gas (per mcf)
	($)	($)	($)	($)
1998	14.84	2.17	8.41	1.41
1997	22.50	2.31	8.70	1.30
1996	25.47	1.64	8.67	.79

(4) Productive Wells and Acreage

Productive wells and acreage on working and carried interest properties as of December 31, 1998 are as follows:

Gross Wells		Net Wells	
Oil	Gas	Oil	Gas
46.0	69.0	6.72	11.49

	Gross and Net Developed Acres	
	Gross Acres	Net Acres
Alberta	3,840	349
British Columbia	46,638	7,681
Yukon Territory	3,350	1,005
Arctic Islands	3,060	153
Texas, USA	160	33
California, USA	262	79
	57,310	9,300

(5) Undeveloped Acreage

Total developed and undeveloped acreage in which the Company has interests is summarized by geographic area in the table below:

Gross and Net Petroleum Acreage as of December 31, 1998

	Developed Acres			Undeveloped Acres		
	Gross Acres	Net Acres	%	Gross Acres	Net Acres	%
Canada:						
British Columbia:						
Carried Interests	28,592	6,039	21.1	6,415	1,363	21.2
Working Interests	6,269	1,005	16.0	11,913	7,797	65.5
Overriding royalty interest	11,777	637	5.4	6,123	95	1.6
Total British Columbia	46,638	7,681		24,451	9,255	
Saskatchewan:						
Working Interests				3,200	120	3.8
Alberta:						
Working Interests	1,920	326	17.0	26,869	8,448	31.4
Overriding Royalty Interest	1,920	23	1.2	640	21	3.3
Total Alberta	3,840	349		27,509	8,469	
Yukon & Northwest Territories:						
Carried Interests	3,350	1,005	30.0	31,726	9,757	30.8
Arctic Islands:						
Carried Interests	3,060	153	5.0	128,670	37,027	28.8
Working Interests	-	-		45,100	1,817	4.0
Total Arctic Islands	3,060	153		173,770	38,844	
Total Canada	56,888	9,188		260,656	66,445	
California, USA	262	79	30.2	-	-	
Texas, USA	160	33	20.6	889	889	100
Total United States	422	112		889	889	
TOTAL	57,310	9,300		261,545	67,334	

(6) Drilling activity

Productive and dry net wells drilled during the following periods:

	Gross		Net	
Year	Productive	Dry	Productive	Dry
1998	9	2	1.440	.200
1997	25	2	3.606	.250
1996	10	2	1.044	.150

(7) Present Activities

There were no wells drilling at December 31, 1998.

(8) Delivery Commitments

None.

Item 3. Legal Proceedings

The Company, which has a 30% interest in the Kotaneelee gas field, believes that the working interest owners in the field have not adequately pursued the attainment of contracts for the sale of Kotaneelee gas. In October 1989 and in March 1990, the Company filed statements of claim in the Court of Queens Bench of Alberta, Judicial District of Calgary, Canada, against the working interest partners in the Kotaneelee gas field. The named defendants were Amoco Canada Petroleum Corporation, Ltd., Dome Petroleum Limited (now Amoco Canada Resources Ltd.), and Amoco Production Company (collectively the "Amoco Dome Group"), Columbia Gas Development of Canada Ltd. ("Columbia"), Mobil Oil Canada Ltd. ("Mobil") and Esso Resource of Canada Ltd. ("Esso") (collectively the "Defendants").

The Company claims that the Defendants breached either a contract obligation and/or a fiduciary duty owed to the Company to market gas from the Kotaneelee gas field when it was possible to so do. The Company asserts that marketing the Kotaneelee gas was possible in 1984 and that the Defendants deliberately failed to do so. The Company seeks money damages and the forfeiture of the Kotaneelee gas field. The Company presented evidence at trial that the money damages sustained by the Company were approximately $100 million.

In addition, the Company has claimed that the Company's carried interest account should be reduced because of improper charges to the carried interest account by the Defendants. The Company claims that when the Defendants in 1980 suspended production from the field's gas wells, they failed to take precautionary measures necessary to protect and maintain the wells in good operating condition. The wells thereafter deteriorated, which caused unnecessary expenditures to be incurred, including expenditures to redrill one well. In addition, the Company claims that expenditures made to repair and rebuild the field's dehydration plant should not have been necessary had the facilities been properly constructed and maintained by the Defendants. The expenditures, the Company claims, were inappropriately charged to the field's carried interest account. The effect of an increased carried interest account is to extend the period before payout begins to the carried interest account owners.

The Company claims that production from the field should have commenced in 1984. At that time the field's carried interest account was approximately $63 million. The Company claims that by 1993 at least $34 million of unnecessary expenses had been wrongfully charged to the carried interest account. The Company's 30% share of these expenses would be approximately $10.2 million. The Company further claims that if production had commenced in 1984, the carried interest account would have been paid off in approximately two years and the Company would have begun to receive revenues from the field in 1986. At present, the Company does not expect to receive revenues before the year 2000, based on a price of Cdn. $1.28 per mcf and current production rates.

Columbia has filed a counterclaim against the Company seeking, if the Company is successful in its claim for the forfeiture of the field, repayment from the Company of all sums Columbia has expended on the Kotaneelee lands before the Company is entitled to its interest.

The parties to the litigation have conducted extensive discovery since the filing of the claims. The trial began on September 3, 1996 and the Company completed the presentation of its case against the Defendants on September 16, 1998. Based upon newly discovered evidence, the Company filed a new claim during May 1998 that the Defendants failed to develop the field in a timely manner. The Company is unable to estimate the time necessary to conclude the litigation.

Matters Ancillary to Kotaneelee Litigation

In its 1989 statement of claim, the Company sought a declaratory judgment regarding two issues:

(1) whether interest accrued on the carried interest account; and

(2) whether expenditures for gathering lines and dehydration equipment are expenditures chargeable to the carried interest account or whether the Company will be assessed a processing fee on gas throughput.

With respect to the first issue, the Company maintains that no interest should accrue on the account and the Defendants have not contested this position. With regard to the second issue, the Company maintains that the expenditures are chargeable to the carried interest account. Mobil, Esso and Columbia have essentially agreed to the Company's position while the Amoco Dome Group continues to contest this issue.

On January 22, 1996, the Company settled two claims outstanding against the Company in the Court of Queens Bench, Calgary, Alberta, which related to a suit brought against AlliedSignal Inc. ("AlliedSignal") in Florida which was dismissed on the basis that Canada was the appropriate forum for the litigation. AlliedSignal had sought additional relief against the Company in Canada to preclude other types of suits by the Company and to recover the costs of the defense of the initial action. The settlement bars AlliedSignal from making a claim against the Company for any costs in connection with the Kotaneelee Litigation. The Company agreed not to bring any action against AlliedSignal in connection with the Kotaneelee gas field. Neither party made any monetary payment to the other party.

In 1991, Anderson Exploration Ltd. acquired all of the shares in Columbia and changed its name to Anderson Oil & Gas Inc. ("Anderson"). Anderson is now the sole operator of the field and is a direct defendant in the Canadian lawsuit. Columbia's previous parent, The Columbia Gas System, Inc., which was reorganized in a bankruptcy proceeding in the United States, is contractually liable to Anderson in the legal proceedings currently at trial.

The working interest owners have reported that they have been selling Kotaneelee gas since February 1991.

Under Canadian law, certain costs (known as "taxable costs") of the litigation may be assessed against the non-prevailing party. Previously, the Company had reported that while such costs were not determinable, the Company estimated that taxable costs, assuming a twelve month trial, could be approximately $1.5 million and noted that the judge in complex and lengthy trials has the discretion to increase an award.

Effective September 1, 1998, the Alberta Rules of Court were amended to provide for a material increase in the costs which may be awarded to the prevailing party in matters before the Court. In addition, the Company believes that the trial will extend well beyond its original time estimates and, therefore, potentially assessable costs would increase accordingly.

The trial has been lengthy, complicated and costly to all parties and the Company believes that the prevailing party or parties in the litigation will argue for a substantial assessment of costs against the non-prevailing party or parties. The Court has very broad discretion as to whether to award costs and disbursements and as to the calculation of the amount to be awarded. Accordingly, the Company is unable to determine whether, in the event that it does not prevail on its claims in the litigation, costs will be assessed against it or in what amount. However, since the costs incurred by the Defendants have been substantial, and since the Court has broad discretion in the awarding of costs, an award to the Defendants potentially could be material. A cost award against the Company could be of sufficient magnitude to necessitate a sale of Company assets or a debt or equity financing to fund such an award. There are no assurances that any such sale or financing would be consummated.

There is no assurance whatever that the Company will be successful on the merits of its claims, which have been vigorously defended by the Defendants. There is also no assurance that the Company will be awarded any damages, or that, if damages are awarded, the Court will apply the measure of damages the Company claims should be applied.

Item 4. Submission of Matters to a Vote of Security Holders

Not applicable.

Executive Officers of the Company

The following information with respect to the executive officers of the Company is furnished pursuant to Instruction 3 to Item 401(b) of Regulation S-K.

Name	Age	Office	Length of Service in this Office	Other Positions Held with Company
M. A. Ashton	63	President	Since June 4, 1997	Director

All officers of the Company are elected annually by the Board of Directors and serve at the pleasure of the Board of Directors.

The Company is aware of no arrangement or understanding between the individual named above and any other person pursuant to which any individual was selected as an officer.

PART II

Item 5. Market for the Company's Limited Voting Shares and Related Stockholder Matters

(a) Principal Markets

The Company's Limited Voting Shares, par value $1.00 per share, are traded on The Toronto, Pacific and Boston Stock Exchanges, and in the NASDAQ SmallCap Market.

The quarterly high and low closing prices (in Canadian dollars) on The Toronto Stock Exchange during the calendar periods indicated were as follows:

1997	1st quarter	2nd quarter	3rd quarter	4th quarter
High	11.00	12.50	16.60	15.00
Low	8.50	7.50	12.25	10.75

1998	1st quarter	2nd quarter	3rd quarter	4th quarter
High	11.75	10.50	9.00	10.00
Low	9.00	8.00	5.50	6.25

The quarterly high and low closing prices (in United States dollars) on the Pacific Exchange, Inc. during the calendar periods indicated were as follows:

1997	1st quarter	2nd quarter	3rd quarter	4th quarter
High	8	9	11 15/16	11
Low	6½	5¾	8 13/16	7¼

1998	1st quarter	2nd quarter	3rd quarter	4th quarter
High	8 5/16	7 5/8	6 3/16	6½
Low	6 3/8	5¾	3½	4 3/16

(b) Approximate Number of Holders of Limited Voting Shares at March 15, 1999

Title of Class	Approximate Number of Record Holders
Limited Voting Shares, par value $1.00 per share.	4,600

(c) Dividends

The Company has never paid a dividend on its Limited Voting Shares. Any future dividends will be dependent on the Company's earnings, financial condition, and business prospects. The Company is legally restricted from paying any dividend or making any other payment to shareholders (except by way of return of capital) on the Limited Voting Shares until its accumulated deficit ($23,849,000 at December 31, 1998) is eliminated.

Current Canadian law does not restrict the remittance of dividends to persons not resident of Canada. Under current Canadian tax law and the United States-Canada tax treaty, any dividends paid to U.S. shareholders are currently subject to a 15% Canadian withholding tax.

Item 6. Selected Financial Data

The following selected consolidated financial information (in thousands except per share and exchange rate data) of the Company insofar as it relates to each of the fiscal periods shown has been extracted from the Company's consolidated financial statements.

	Year ended December 31,				
	1998 ($)	1997 ($)	1996 ($)	1995 ($)	1994 ($)
Operating revenues	1,810	2,120	1,755	1,657	1,691
Total revenues	3,409	2,515	2,228	1,793	1,942
Net loss	(2,707)	(1,758)	(1,461)	(1,162)	(1,210)
Net loss per share	(.19)	(.12)	(.11)	(.09)	(.10)
Working capital	6,876	5,573	8,403	1,510	2,417
Total assets	17,546	20,956	20,375	12,380	13,390
Shareholders' Equity:					
Capital stock	40,489	40,489	38,888	29,635	29,513
Deficit	(23,849)	(21,143)	(19,385)	(17,923)	(16,762)
	16,640	19,346	19,503	11,712	12,751
Average number of shares outstanding	14,235	14,084	13,362	12,622	12,613
Exchange rates:					
Year-end	.6535	.6992	.7297	.7329	.7129
Average for the period	.6749	.7224	.7335	.7289	.7324
Range	.63-.67	.69-.75	.72-.75	.70-.75	.71-.76

U.S. GAAP Information

Under U.S. generally accepted accounting principles ("GAAP"), the above selected information would be as follows (See Note 6 in Notes to Consolidated Financial Statements):

Net loss	(2,328)	(1,588)	(1,236)	(1,001)	(1,140)
Net loss per share	(.16)	(.11)	(.09)	(.08)	(.09)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Statements included in Management's Discussion and Analysis of Financial Condition and Results of Operations which are not historical in nature are intended to be, and are hereby identified as, "forward looking statements" for purposes of the "Safe Harbor" Statement under the Private Securities Litigation Reform Act of 1995. The Company cautions readers that forward looking statements are subject to certain risks and uncertainties that could cause actual results to differ materially from those indicated in the forward looking statements.

(1) Liquidity and Capital Resources

At December 31, 1998, the Company had approximately $7 million of cash and securities available which amount includes the $5.7 million proceeds from the sale of certain properties that was completed in November 1998. These funds are expected to be used for general corporate purposes, including exploration and development and to continue the Kotaneelee field litigation. The Company estimates that it currently has adequate working capital for 1999 and 2000. However, it might be required to raise additional funds through the sale of properties or other means in order to complete the Kotaneelee Litigation.

Cash flow used in operations during 1998 increased to $2,351,000 compared to $1,003,000 during the 1997 period. The $1,348,000 difference between the periods was caused primarily by the following:

Increase in loss from operations	$(1,332,000)
Increase in accounts receivable and other	1,488,000
Net change in current liabilities	(1,504,000)
Increase in net cash used in operations	$(1,348,000)

A significant proportion of the Company's property interests are covered by carried interest agreements, which provide that expenditures made by the operator are recouped solely out of revenues from production. Major capital expenditures made by the operators have an impact on the Company's cash flow from operations as no revenues are reported or received until the capital costs have been recovered by the operator. Certain properties in the Fort Nelson, British Columbia area in which the Company has carried interests have reached payout status. Proceeds from these carried interests plus oil and gas sales from working interest properties are the Company's major sources of working capital. During 1998, the Company sold the majority of its Canadian working interest oil and gas properties, therefore, the Company expects a significant decrease in its 1999 revenues, royalties and lease operating expenses.

The Company is currently evaluating and expects to continue to evaluate oil and gas properties and may make investments in such properties utilizing cash on hand. The Company anticipates that its capital expenditures for land acquisitions and drilling for the year 1999 will be approximately $1,200,000. In addition, substantial continuing expenses are expected to be incurred in connection with the Kotaneelee Litigation. During 1998, the Company expended approximately $2.4 million in connection with the Kotaneelee Litigation which has been the principal cause of the Company's losses since 1991.

The Company has established a reserve for its potential share of future site restoration costs. The estimated amount of these costs, which total $271,000, is being provided on a unit of production basis in accordance with existing legislation and industry practice.

At December 31, 1998, the Company believes that it is year 2000 compliant. In addition, the year 2000 change will have no material impact on the Company's internal operations or financial results. However, the Company will be dependent on its suppliers, partners and customers to make their systems year 2000 compliant.

(2) Results of Operations

1998 vs. 1997

The net loss for the year 1998 was $2,706,537, ($.19 per share) compared to a net loss of $1,757,664 ($.12 per share) for the 1997 period. A summary of revenue and expenses during the periods is as follows:

	1998	1997	Net Change
Revenues	$ 3,409,361	$ 2,514,978	$ 894,383
Costs and expenses	(6,115,898)	(4,272,642)	(1,843,256)
Net loss	$(2,706,537)	$(1,757,664)	$ (948,873)

Oil sales decreased by 20% due primarily to a 34% decrease in the average prices of oil sold which was partially offset by a 2% increase in production. There was also a decrease in royalties paid by the Company. The Company sold the majority of its oil producing properties in two separate transactions effective July 1, 1998 and September 1, 1998. The 1998 royalties paid amount includes a provincial royalty tax credit in the amount of $117,000. Oil unit sales in barrels ("bbls") (before deducting royalties) and the average price per barrel sold during the periods indicated were as follows:

	1998			1997		
	bbls	Average price per bbl	Total	bbls	Average price per bbl	Total
Oil sales	64,954	$14.84	$964,000	63,783	$22.50	$1,436,000
Royalties paid			(66,000)			(315,000)
Total			$898,000			$1,121,000

Gas sales increased 35% because of a 52% increase in number of units sold which was partially offset by a 6% decrease in the average price for gas. In addition, gas sales include royalty income which decreased 13% in 1998. The Company sold the majority of its working interest gas properties effective July 1, 1998. The primary increase in gas production was the payout of two wells that had been in a penalty position. These wells were included in the properties sold. The volumes in million cubic feet ("mmcf") and the average price of gas per thousand cubic feet ("mcf") sold during the periods indicated were as follows:

	1998			1997		
	mmcf	Average price per mcf	Total	mmcf	Average price per mcf	Total
Gas sales	304	2.17	$660,000	200	2.31	$462,000
Royalty income			127,000			146,000
Royalties paid			(82,000)			(85,000)
Total			$705,000			$523,000

Proceeds under carried interest agreements decreased 57% to $207,000 during 1998 compared to $476,000 in 1997. During 1998, there were significant expenditures made by the operators of the carried interest properties, therefore, revenues from these properties will be substantially lower in 1999.

Interest and other income decreased 44% in 1998. Interest income decreased from $336,000 to $194,000 in 1998 due to the decrease in funds available for investment and lower interest rates. In addition, the 1998 period includes proceeds from the sale of seismic data in the amount of $27,000 compared to $59,000 from such sales in 1997. Interest income should increase in 1999 with the increased funds available from the 1998 sale of properties. It is not possible for the Company to estimate the amount of future seismic data sales which are dependent on a purchaser's evaluation of a prospective oil and gas prospect for the related seismic data that the Company owns.

Gain on the sale of properties in 1998 amounted to $1,378,000 primarily represents the sale of the Company's heavy oil properties in Alberta and the sale of certain working interest properties in British Columbia.

General and administrative costs increased 18% in 1998 to $1,301,000 from $1,105,000 in 1997 primarily as a result of increased Company activity in connection with the Kotaneelee litigation and the Company's exploration program. In addition, the expenses increased in the United States because of the 7% increase in the value of the U.S. dollar compared to the Canadian dollar during 1998.

Legal expenses increased 24% during 1998 to $2,358,000 compared to $1,898,000 during 1997. These expenses are related primarily to the cost of the Kotaneelee litigation. During 1998, the Company continued the presentation of a major part of its case against the working interest partners. The Company's case was completed on September 16, 1998 and Defendants' case is now proceeding. The 1998 costs represent both legal fees and the cost of various Company experts who testified, were being prepared for testimony, or assisted in the cross-examination of defense witnesses.

Lease operating costs increased 22% from $799,000 in 1997 to $976,000 in the 1998 period. The increase represents the charges by the operators of the Company's properties which is related to the increased production. In addition, the Company's share of production costs in producing Alberta heavy oil increased. Lease operating costs should decrease in 1999 because of the 1998 sale of properties.

Depletion, depreciation and amortization expense increased 39% in 1998 to $870,000 from $624,000 in 1997. The increase in depletion in 1998 is the result of increased production and the amount of additional costs being depleted.

A foreign exchange gain of $179,000 was recorded in 1998, contrasted with a gain of $231,000 on the Company's U.S. investments in 1997. In 1998, the gain was attributable to the continuing strengthening of the U.S. dollar as compared to the Canadian dollar on the Company's U.S. investments.

Abandonments and write downs were $685,000 which resulted from a write down of certain of the Company's properties in California and Texas. There were no abandonments and write downs in 1997.

Income taxes. No provision for income taxes was required in 1998. There has been no income tax recovery recorded in the accounts for the Company's losses because there is a lack of virtual certainty that the recovery will be realized. If at such time as the Company begins to receive revenues from the Kotaneelee gas field, it is expected that the tax recovery benefit of these losses will be recognized.

1997 vs. 1996

The net loss for the year 1997 was $1,757,664, ($.12 per share) compared to a net loss of $1,461,283 ($.11 per share) for the 1996 period. A summary of revenue and expenses during the periods is as follows:

	1997	1996	Net Change
Revenues	$2,514,978	$2,228,393	$286,585
Costs and expenses	(4,272,642)	(3,689,676)	(582,966)
Net loss	$(1,757,664)	$(1,461,283)	$(296,381)

Oil sales increased by 46% due primarily to an 85% increase in production which was partially offset by a 12% decrease in the average prices of oil sold. There was also a 184% increase in royalties paid by the Company. Oil unit sales in barrels ("bbls") (before deducting royalties) and the average price per barrel sold during the periods indicated were as follows:

	1997			1996		
	bbls	Average price Per bbl	Total	bbls	Average price per bbl	Total
Oil sales	63,783	$22.50	$1,436,000	34,565	$25.47	$880,000
Royalties paid			(315,000)			(111,000)
Total			$1,121,000			$769,000

Gas sales increased 33%. There was a 41% increase in the average price for gas and a 2% increase in number of units sold. In addition, gas sales include royalty income which increased 35% in 1997. The volumes in million cubic feet ("mmcf") and the average price of gas per thousand cubic feet ("mcf") sold during the periods indicated were as follows:

	1997			1996		
	mmcf	Average price per mcf	Total	mmcf	Average price per mcf	Total
Gas sales	200	$2.31	$462,000	197	$1.64	$323,000
Royalty income			146,000			108,000
Royalties paid			(85,000)			(36,000)
Total			$523,000			$395,000

Proceeds under carried interest agreements decreased 20% to $476,000 during 1997 compared to $591,000 in 1996. The operator of the Company's carried interest properties increased its development activities during late 1996, thereby incurring additional capital costs which were deducted in 1997. Proceeds under carried interest agreements are derived from net production revenues after payout of capital costs.

Interest and other income decreased 17% in 1997. Interest income increased from $259,000 to $336,000 in 1997 due to the increase in funds available for investment from the June 1996 rights offering to shareholders. In addition, the 1997 period includes proceeds from the sale of seismic data in the amount of $59,000 compared to $215,000 from such sales in 1996.

General and administrative costs increased 23% in 1997 to $1,105,000 from $895,000 in 1996. Capital taxes, which are based on the Company's net worth, increased $48,000 in 1997. Directors' fees increased $44,000 in 1997 because four nonemployee directors are being paid fees in 1997 compared to 1996 when only two directors were paid fees. Geological and engineering expenses increased $23,000 in 1997 because of the Company's active exploration program. Shareholders' expenses increased $32,000 in 1997 compared to 1996 because of increased printing and mailing costs. Salaries increased $39,000 in 1997 with the addition of a new employee.

Legal expenses increased 18% during 1997 to $1,898,000 compared to $1,610,000 during 1996. These expenses are related primarily to the cost of the Kotaneelee litigation. During 1997, the Company presented a major part of its case against the working interest partners. The 1997 costs represent both legal fees and the cost of various Company experts who testified or were being prepared for testimony.

Lease operating costs increased 68% from $477,000 in 1996 to $799,000 in the 1997 period. The increased costs are relative to the 85% increase in oil production. Although the revenue on these properties also increased during the period, the costs are not yet proportional to revenue because some of the new wells are awaiting installation of production facilities.

A foreign exchange gain of $231,000 was recorded in 1997, contrasted with a gain of $25,000 on the Company's U.S. investments in 1996. In 1997, the gain was attributable to a strengthening of the U.S. dollar as compared to the Canadian dollar on the Company's U.S. investments.

Income taxes. No provision for income taxes is required for the current period.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

The Company does not have any significant exposure to market risk as the only market risk sensitive instruments are its investments in marketable securities. At December 31, 1998, the carrying value of such investments was approximately $6,703,000 which was approximately equal to fair value and face value of the investments. Since the Company expects to hold the investments to maturity, the maturity value should be realized. In addition, the Company's investments in marketable securities included investments held in the United States which are subject to foreign exchange fluctuations. At December 31, 1998, the investments in the United States totaled $1,823,000.

Item 8. Financial Statements and Supplementary Data

AUDITORS' REPORT

To the Shareholders of
Canada Southern Petroleum Ltd.

We have audited the consolidated balance sheets of Canada Southern Petroleum Ltd. as at December 31, 1998 and 1997, and the consolidated statements of operations and deficit, cash flows and limited voting shares and contributed surplus for each of the years in the three year period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canada Southern Petroleum Ltd. as at December 31, 1998 and 1997 and the results of its operations and the changes in its financial position for each of the years in the three year period ended December 31, 1998, in accordance with accounting principles generally accepted in Canada.

Calgary, Canada
March 18, 1999

/s/ ERNST & YOUNG LLP
Chartered Accountants

CANADA SOUTHERN PETROLEUM LTD.
(Incorporated under the laws of Nova Scotia)

CONSOLIDATED BALANCE SHEETS
(Expressed in Canadian dollars)

	As at December 31,	
	1998	1997
Assets		
Current assets		
Cash and cash equivalents (Note 2)	$ 6,208,634	$ 2,129,156
Marketable securities (Note 3)	751,511	3,373,334
Accounts receivable (Notes 4 and 7)	266,116	1,226,086
Other assets	319,697	242,278
Total current assets	7,545,958	6,970,854
Oil and gas properties and equipment (full cost method) (Note 4)	10,000,010	13,984,771
Total assets	$17,545,968	$20,955,625
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$ 375,554	$ 1,120,521
Accrued liabilities (Note 10)	294,491	277,715
Total current liabilities	670,045	1,398,236
Future site restoration costs	236,045	210,974
Contingencies (Note 8)	-	-
Shareholders' Equity		
Limited Voting Shares, par value $1 per share (Note 5)		
Authorized – 100,000,000 shares		
Outstanding – 14,234,740 shares	14,234,740	14,234,740
Contributed surplus	26,254,139	26,254,139
Total capital	40,488,879	40,488,879
Deficit	(23,849,001)	(21,142,464)
Total shareholders' equity	16,639,878	19,346,415
Total liabilities and shareholders' equity	$17,545,968	$20,955,625

See accompanying notes.

Approved on behalf of the Board

/s/ M. A. Ashton
Director

/s/ Arthur B. O'Donnell
Director

CANADA SOUTHERN PETROLEUM LTD.

Consolidated Statements of Operations and Deficit
(Expressed in Canadian dollars)

	Year ended December 31,		
	1998	**1997**	**1996**
Revenues:			
Oil sales (Notes 9 and 10)	$ 897,878	$ 1,120,789	$ 768,576
Gas sales (Notes 9 and 10)	705,277	523,433	395,068
Proceeds under carried interest agreements	206,503	475,697	590,935
Interest and other income	221,523	395,059	473,814
Gain on sale of assets	1,378,180	-	-
Total revenues	3,409,361	2,514,978	2,228,393
Costs and expenses:			
General and administrative	1,300,595	1,104,535	894,766
Legal (Note 8)	2,357,707	1,897,506	1,610,477
Lease operating costs	975,899	799,372	476,562
Depletion, depreciation and amortization	869,600	623,600	654,982
Foreign exchange gains	(178,850)	(231,457)	(24,693)
Provision for future site restoration costs	29,500	21,500	24,600
Rent	76,812	57,586	52,982
Abandonments and write downs	684,635	-	-
Total costs and expenses	6,115,898	4,272,642	3,689,676
Loss before income taxes	(2,706,537)	(1,757,664)	(1,461,283)
Income taxes (Note 6)	-	-	-
Net loss	(2,706,537)	(1,757,664)	(1,461,283)
Deficit – beginning of period	(21,142,464)	(19,384,800)	(17,923,517)
Deficit - end of period	$(23,849,001)	$(21,142,464)	$(19,384,800)
Net loss per share (Basic & Fully Diluted)	$(.19)	$(.12)	$(.11)
Average number of shares Outstanding (Basic & Fully Diluted)	14,234,740	14,084,294	13,362,410

See accompanying notes.

CANADA SOUTHERN PETROLEUM LTD.

Consolidated Statements of Cash Flows
(Expressed in Canadian dollars)

	Year ended December 31,		
	1998	1997	1996
Cash flows from operating activities:			
Net loss	$(2,706,537)	$(1,757,664)	$(1,461,283)
Adjustments to reconcile net loss to net cash provided by (used in) operating activity:			
Depreciation, depletion and amortization	869,600	623,600	654,982
Future site restoration costs (net)	25,071	(39,300)	(56,454)
Gain on sale of assets	(1,378,180)	-	-
Abandonments and write downs	684,635	-	-
Change in assets and liabilities:			
Accounts and interest receivable	959,970	(590,863)	(284,625)
Other assets	(77,419)	(14,910)	112,074
Accounts payable	(744,967)	680,684	314,328
Accrued liabilities	16,776	95,611	(54,228)
Net cash used in operations	(2,351,051)	(1,002,842)	(775,206)
Cash flows from investing activities:			
Additions to oil and gas properties (net)	(1,942,474)	(3,258,426)	(1,496,308)
Sale (purchase) of marketable securities	2,621,823	2,079,452	(5,452,786)
Proceeds from the sale of properties	5,751,180	-	-
Net cash used in investing activities	6,430,529	(1,178,974)	(6,949,094
Cash flows from Financing Activities:			
Sale of common stock less expenses	-	-	9,019,609
Exercise of stock options	-	1,601,375	232,707
Net cash from financing activities	-	1,601,375	9,252,316
Increase (decrease) in cash and cash equivalents	4,079,478	(580,441)	1,528,016
Cash and cash equivalents at the beginning of period	2,129,156	2,709,597	1,181,581
Cash and cash equivalents at the end of period (Note 2)	$6,208,634	$2,129,156	$2,709,597

See accompanying notes.

CANADA SOUTHERN PETROLEUM LTD.

CONSOLIDATED STATEMENTS OF LIMITED VOTING SHARES AND CONTRIBUTED SURPLUS

(Expressed in Canadian dollars)

	Number of shares	Limited Voting Shares $1 par value	Contributed surplus	Total
Balance as at December 31, 1995	12,645,791	12,645,791	16,989,397	29,635,188
Sale of common stock	1,268,549	1,268,549	7,751,060	9,019,609
Exercise of stock options	42,200	42,200	190,507	232,707
Balance as at December 31, 1996	13,956,540	13,956,540	24,930,964	38,887,504
Exercise of stock options	278,200	278,200	1,323,175	1,601,375
Balance as at December 31, 1997 and 1998	14,234,740	$14,234,740	$26,254,139	$40,488,879

See accompanying notes.

1. Summary of significant accounting policies

Accounting principles

The Company prepares its accounts in accordance with accounting principles generally accepted in Canada which, except as described in Note 6, conform in all material respects with United States generally accepted accounting principles ("U.S. GAAP").

Consolidation

The consolidated financial statements include the accounts of Canada Southern Petroleum Ltd. and its wholly-owned subsidiaries, Canpet Inc. and C.S. Petroleum Limited.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Specifically estimates were utilized in calculating depletion, depreciation and amortization, site restoration costs, and abandonments and write downs. Actual results could differ from those estimates.

Cash and cash equivalents

For the purposes of the statement of cash flows, the Company considers all highly liquid investments with a maturity of three months or less to be cash equivalents.

Oil and gas properties and equipment

The Company, which is engaged primarily in one industry, the exploration for and the development of oil and gas properties, principally in Canada, follows the full cost method of accounting for oil and gas properties, whereby all costs associated with the exploration for and the development of oil and gas reserves are capitalized. Such costs include land acquisition, drilling, geological, geophysical and overhead expenses.

The Company periodically reviews the costs associated with undeveloped properties and mineral rights to determine whether they are likely to be recovered. When such costs are not likely to be recovered, such costs are transferred to the depletable pool of oil and gas costs.

1. **Summary of significant accounting policies (Cont'd)**

The net carrying cost of the Company's oil and gas properties in producing cost centers is limited to an estimated recoverable amount. This amount is the aggregate of future net revenues from proved reserves and the costs of undeveloped properties, net of impairment allowances, less future general and administrative costs, financing costs and income taxes. Future net revenues are calculated using year end prices that are not escalated or discounted. For Canadian GAAP future net revenues are undiscounted, whereas, for U.S. GAAP future net revenues are discounted at 10%.

The costs of the Company's 30% carried interest in the Kotaneelee gas field are included in oil and gas properties and in the cost center for the purpose of computing depletion. In addition, the Company's share of estimated net reserves after payout are also included in the proved oil and gas reserves base for the purpose of computing depletion. However, no revenue production data will be reported for financial statement purposes until the Company is entitled to participate in the field's revenue after payout status is achieved.

Gains or losses are not recognized upon disposition of oil and gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion is provided on costs accumulated in producing cost centers including production equipment using the unit of production method. For purposes of the depletion calculation, gross proved oil and gas reserves as determined by outside consultants are converted to a common unit of measure on the basis of their approximate relative energy content.

Depreciation has been computed for equipment, other than production equipment, on the straight-line method based on estimated useful lives of four to ten years.

Substantially all of the Company's exploration and development activities related to oil and gas are conducted jointly with others and accordingly the consolidated financial statements reflect only the Company's proportionate interest in such activities.

Revenue recognition

The Company recognizes revenue on its working interest properties from the production of oil and gas in the period the oil and gas are sold.

1. **Summary of significant accounting policies (Cont'd)**

Revenue under carried interest agreements is recorded in the period when the proceeds become receivable. The Company is entitled to participate in oil and gas net revenues after the repayment of exploration, drilling and completion expenses to the party or parties bearing these costs. The carried interest accounts are subject to independent audits which are performed in subsequent years. In the past, these audits have resulted in both positive and negative adjustments. For these reasons, the proceeds under carried interest agreements may fluctuate each year depending on both capital expenditures and any audit adjustments.

Earnings per share

Earnings per common share is based upon the weighted average number of common and common equivalent shares outstanding during the period. In February 1997, the FASB issued Statement No. 128, Earnings per Share ("EPS"), which the Company adopted retroactively in 1997 for purposes of U.S. GAAP reporting. The Company's basic and diluted calculations of EPS are the same for both U.S. and Canadian GAAP.

Future site restoration costs

Total future site restoration costs are estimated to be $271,000 and are being provided on a unit of production basis. The provision is based on current costs of complying with existing legislation and industry practice for site restoration and abandonment. At December 31, 1998, approximately $36,000 in such costs have yet to be accrued. The sale of the Company's Alberta and British Columbia properties during 1998 relieved the Company of $533,000 of potential future restoration costs.

Income taxes

The Company follows the deferral method of tax allocation accounting whereby the income tax provision is based on pre-tax income reported in the accounts. Under this method, full provision is made for deferred income taxes resulting from claiming deductions at the rates permitted by income tax legislation, which may differ from those used in the accounts.

Foreign currency translation

Transactions for settlement in U.S. dollars have been translated at average monthly exchange rates. Assets and liabilities in U.S. dollars have been translated at the year end exchange rates. Exchange gains or losses resulting from these adjustments are included in costs and expenses.

(Expressed in Canadian dollars)

1. Summary of significant accounting policies (Cont'd)

Financial instruments

The carrying value for cash and cash equivalents, accounts receivable and accounts payable approximates fair value based on anticipated cash flows and current market conditions.

Comprehensive income

In 1997, the Financial Accounting Standards Board issued FASB Statement No. 130, Reporting Comprehensive Income. As the Company has no items of other comprehensive income, the net loss under U.S. GAAP for all periods presented is equal to the comprehensive loss.

2. Cash and cash equivalents

The Company considers all highly liquid short term investments with maturities of three months or less at date of acquisition to be cash equivalents. Cash equivalents are carried at cost which approximates market value.

	1998	1997
Cash	$ 269,918	$ 436,030
Canadian and U.S. bankers acceptances (1998-4.9%, 1997-2.9%)	4,880,833	988,437
U.S. Government securities (1998-4.8%, 1997-5.6%)	1,057,883	704,689
	$6,208,634	$2,129,156

3. Marketable Securities

At December 31, 1998 and 1997, the Company held the following marketable securities which were expected to be held until maturity:

1998

Security	Par value	Maturity Date	Amortized Cost	Fair value
U.S. Federal National Mortgage Assoc.	$765,111	Apr. 7, 1999	$751,511	$751,711

1997

Security	Par value	Maturity Date	Amortized Cost	Fair value
U.S. Federal Home Bank Note	$ 143,021	Mar. 6, 1998	$ 140,418	$ 141,247
U.S. Federal Home Bank Note	286,041	Apr. 6, 1998	278,324	280,925
U.S. Federal Farm Credit Bank Note	143,021	May 4, 1998	139,600	139,469
U.S. Treasury Note	2,145,309	May 31, 1998	2,137,934	2,149,321
U.S. Federal Home Loan Bank Note	715,103	Jun. 19, 1998	677,058	683,411
Total	$3,432,495		$3,373,334	$3,394,373

(Expressed in Canadian dollars)

4. Oil and gas properties and equipment

	Cost	Less Accumulated Provisions and Writedowns	Net Book Value
Balance December 31, 1998			
Oil and gas properties-developed	$18,524,670	$8,720,066	$ 9,804,605
Oil and gas properties-(U.S.) undeveloped	851,651	684,635	167,016
Seismic data	112,000	112,000	-
	19,488,321	9,516,701	9,971,621
Equipment	75,073	46,684	28,389
	$19,563,394	$9,563,385	$10,000,010
Balance December 31, 1997			
Oil and gas properties – developed	$21,192,037	$7,854,066	$13,337,971
Oil and gas properties (U.S.) - undeveloped	616,980	-	616,980
Seismic data	112,000	112,000	-
	21,921,017	7,966,066	13,954,951
Equipment	67,769	37,949	29,820
	$21,988,786	$8,004,015	$13,984,771

Substantially all gas sales were made to CanWest Gas Supply Inc. and oil sales were made to Probe Exploration, Inc. ("Probe"). The gain on sale of assets and the amount of abandonments and write downs are same under both Canadian and U.S. GAAP. During 1998, a total of $95,000 of general and administrative expenses were capitalized.

The $266,000 amount of accounts receivable is due from various industry partners which include Probe, Berkley Petroleum Ltd., PetroCanada and Alberta Treasury.

5. Limited Voting Shares and stock options

The Memorandum of Association (Articles of Continuance) of the Company provides that no person (as defined) shall vote more than 1,000 shares.

Under the terms of the Company's 1985, 1992 and 1998 stock option plans, the Company is authorized to grant certain employees, directors and consultants options to purchase Limited Voting Shares at prices based on the market price of the shares as determined on the date of the grant. The options are normally exercisable immediately and issued for a period of five years from the date of grant.

On January 27, 1998, the Company's Board of Directors approved a stock option plan that permits the granting of both stock options and stock appreciation rights. The plan for 700,000 shares was approved by the Company's shareholders at the June 1998 Annual Meeting. A total of 700,000 Limited Voting Shares were reserved for the plan.

(Expressed in Canadian dollars)

5. Limited Voting Shares and stock options (Cont'd)

In 1996, the Company sold 1.3 million shares to its shareholders at $7.50 per share. The proceeds to the Company from the rights offering were $9,019,609 after deducting the $494,509 cost of the offering.

Following is a summary of option transactions which reflects adjustments of the stock option prices and the number of shares subject to stock options as discussed above:

Options Outstanding	Expiration Dates	Number of Shares	Option Prices
December 31, 1995	Oct. 1997 – Aug. 1999	461,700	
Canceled		(137,000)	3.45 - 7.00
Exercised		(42,200)	3.45 - 8.75
Granted		150,700	3.15 - 6.37
Granted		12,500	8.75
December 31, 1996	Oct. 1999 – Jun. 2001	445,700	
Exercised		(278,200)	3.70 – 8.75
Granted		35,000	13.50
December 31, 1997	Aug. 1999 – Oct. 2002	202,500	6.37 – 13.50
Granted		7,500	10.25
December 31, 1998	Aug. 1999 – Apr. 2003	210,000	($7.94 weighted average)
Options reserved for future grants		869,634	

On July 8, 1996, 137,000 options to purchase limited voting shares of the Company which were previously granted were canceled and reissued to reflect the June 1996 rights offering.

For U.S. GAAP, the Company has elected to follow Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB No. 25) and related interpretations in accounting for its stock options because the alternative fair value accounting provided under FASB Statement No. 123, "Accounting for Stock Based Compensation," requires use of option valuation models that were not developed for use in valuing stock options. Under APB No. 25, because the exercise price of the Company's stock options equals the market price of the underlying stock on the date of grant, no compensation expense is recognized.

Pro forma information regarding net income and earnings per share is required by Statement 123, and has been determined as if the Company had accounted for its stock options under the fair value method of that Statement. The fair value for these options was estimated at the date of grant using a Black-Scholes option pricing model.

(Expressed in Canadian dollars)

5. Limited Voting Shares and stock options (Cont'd)

Option valuation models require that input of highly subjective assumptions including the expected stock price volatility. All of the valuations assumed no expected dividend. The assumptions used in the 1996 valuation model were: risk free interest rate - 6.7%, expected life - 5 years and expected volatility - .396. The assumptions used in the 1997 valuation model were: risk free interest rate - 5.7%, expected life - 5 years and expected volatility - .459. The assumptions used in the 1998 valuation model were: risk free interest rate – 4.45%, expected life – 5 years and expected volatility - .328.

Because the Company's stock options have characteristics significantly different from those of traded options, and because changes in the subjective input assumptions can materially affect the fair value estimate, in management's opinion, the existing models do not necessarily provide a reliable single measure of the fair value of its stock options.

For the purpose of pro forma disclosures, the estimated fair value of the stock options is expensed in the year of grant since the options are immediately exercisable. The Company's pro forma information is as follows:

	Amount	Per Share
Net loss as reported Canadian GAAP - December 31, 1996	$(1,461,283)	$(.11)
Stock option expense	49,373	-
Pro forma net loss U.S. GAAP – December 31, 1996	$(1,510,656)	$(.11)
Net loss as reported Canadian GAAP – December 31, 1997	$(1,757,664)	$(.12)
Stock option expense	225,400	(.02)
Pro forma net loss U.S. GAAP – December 31, 1997	$(1,983,064)	$(.14)
Net loss as reported Canadian GAAP – December 31, 1998	$(2,706,537)	$(.19)
Stock option expense	29,600	-
Pro forma net loss U.S. GAAP – December 31, 1998	$(2,736,137)	$(.19)

6. Income taxes

Income taxes vary from the amounts that would be computed by applying the Canadian federal and provincial income tax rates as follows:

	1998	1997	1996
	44.84%	44.84%	44.84%
Provision (recovery) for income taxes based on combined basic Canadian federal and provincial income tax	$(1,213,611)	$(788,137)	$(655,239)
Nondeductible crown charges	104,663	154,463	61,599
Resource allowance	403,270	232,922	-
Other	24,919	21,106	478
Nontaxable portion of capital gain	(20,049)	(20,743)	-
Unrealized tax loss	700,808	400,389	593,162
Actual provision for income taxes	$ -	$ -	$ -

(Expressed in Canadian dollars)

6. **Income taxes (Cont'd)**

At December 31, 1998, the Company had net operating losses for income tax purposes of approximately $3,821,000 which are available to be carried forward to future periods. These losses expire in the following years: 1999 - $194,000, 2000 - $294,000, 2001 - $545,000, 2002 - $569,000, 2003 - $1,077,000, 2004 - $544,000 and 2005 - $1,711,000.

At December 31, 1998, the following oil and gas tax deductions are available to reduce future taxable income, subject to a final determination by taxation authorities.

Canada	
Drilling, exploration and lease acquisition costs	$9,965,000
Earned depletion	1,975,000
Undepreciated capital costs	2,322,000
Cumulative eligible capital losses	407,000
Share issue costs	175,000
United States	
Exploration and lease acquisition costs	$819,000

The tax benefits attributable to the above accumulated expenditures will not be reflected in the consolidated financial statements until such benefits are realized.

Under U.S. GAAP, the provisions for income taxes would have differed for the reasons set out below:

In February 1992, the United States Financial Accounting Standards Board issued Statement No. 109, "Accounting for Income Taxes", effective for fiscal years beginning after December 15, 1993. Under U.S. GAAP, the Company would have been required to adopt Statement No. 109 commencing July 1, 1993.

Under Statement No. 109, the liability method is used in accounting for income taxes. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Under Canadian GAAP and previously under U.S. GAAP, income tax expense is determined using the deferral method. Deferred tax expense is based on items of income and expense that are reported in different years in the financial statements and tax returns and are measured at the tax rate in effect in the year the differences originated.

(Expressed in Canadian dollars)

6. Income taxes (Cont'd)

The following schedule summarized the Company's income tax recovery and deferred tax asset under U.S. GAAP. If Statement No. 109 was adopted, the Company would have had a deferred tax asset which primarily represents the excess of available resource deductions for income tax purposes over the recorded value of oil and gas properties together with operating and capital income tax loss carryforwards. These amounts are expected to be recovered from the production of current oil and gas reserves when the Kotaneelee litigation expenditures have ended. As certain of the resource deductions are restricted and the operating loss carryforwards are subject to expiration, there is considerable risk that certain of these deductions will not be utilized. Accordingly, the Company would have established a valuation allowance to recognize this uncertainty. Income taxes computed in accordance with U.S. GAAP, would have resulted in a credit to the provision of taxes.

	1998	1997	1996
Deferred tax asset	$4,749,727	$3,663,793	$3,233,506
Valuation reserve	(3,441,222)	(2,733,655)	(2,473,526)
Net deferred tax asset	$1,308,505	$ 930,138	$ 759,980
Deferred tax recovery	$ 378,367	$ 170,158	$ 225,222

Net loss under U.S. GAAP, in total, and per share based on average number of shares outstanding during the periods shown is as follows:

	1998	1997	1996
Net loss under Canadian GAAP before income taxes	$(2,706,537)	$(1,757,664)	$(1,461,283)
Income tax adjustment	378,367	170,158	225,222
Net loss under U.S. GAAP	$(2,328,170)	$(1,587,506)	$(1,236,061)
Per Share Basis:			
Net loss under Canadian GAAP before income taxes	$(.19)	$(.12)	$(.11)
Income tax adjustment	.03	.01	.02
Net loss under U.S. GAAP	$(.16)	$(.11)	$(.09)

The deficit under U.S. GAAP would have been $22,540,496 and $20,212,326 at December 31, 1998 and 1997, respectively.

7. Line of credit

The Company has a line of credit with a Canadian chartered bank which provides for a loan of $500,000. The line of credit provides for a $125,000 operating loan and $375,000 for letters of credit as part of the directors' indemnification agreements. The interest rate on borrowing is at ¾% above the bank's prime lending rate. The line of credit is subject to annual review and is secured by a general assignment of accounts receivable and an undertaking to provide security in the form of assignment of future working interest proceeds. No drawings were made under this line during 1998 or 1997.

8. Litigation

The Company, which has a 30% interest in the Kotaneelee gas field, believes that the working interest owners in the field have not adequately pursued the attainment of contracts for the sale of Kotaneelee gas. In October 1989 and in March 1990, the Company filed statements of claim in the Court of Queens Bench of Alberta, Judicial District of Calgary, Canada, against the working interest partners in the Kotaneelee gas field. The named defendants were Amoco Canada Petroleum Corporation, Ltd., Dome Petroleum Limited (now Amoco Canada Resources Ltd.), and Amoco Production Company (collectively the "Amoco Dome Group"), Columbia Gas Development of Canada Ltd. ("Columbia"), Mobil Oil Canada Ltd. ("Mobil") and Esso Resource of Canada Ltd. ("Esso") (collectively the "Defendants").

The Company claims that the Defendants breached either a contract obligation and/or a fiduciary duty owed to the Company to market gas from the Kotaneelee gas field when it was possible to so do. The Company asserts that marketing the Kotaneelee gas was possible in 1984 and that the Defendants deliberately failed to do so. The Company seeks money damages and the forfeiture of the Kotaneelee gas field. The Company presented evidence at trial that the money damages sustained by the Company were approximately $100 million.

In addition, the Company has claimed that the Company's carried interest account should be reduced because of improper charges to the carried interest account by the Defendants. The Company claims that when the Defendants in 1980 suspended production from the field's gas wells, they failed to take precautionary measures necessary to protect and maintain the wells in good operating condition. The wells thereafter deteriorated, which caused unnecessary expenditures to be incurred, including expenditures to redrill one well. In addition, the Company claims that expenditures made to repair and rebuild the field’s dehydration plant should not have been necessary had the facilities been properly constructed and maintained by the Defendants. The expenditures, the Company claims, were inappropriately charged to the field's carried interest account. The effect of an increased carried interest account is to extend the period before payout begins to the carried interest account owners.

8. Litigation (Cont'd)

The Company claims that production from the field should have commenced in 1984. At that time the field's carried interest account was approximately $63 million. The Company claims that by 1993 at least $34 million of unnecessary expenses had been wrongfully charged to the carried interest account. The Company's 30% share of these expenses would be approximately $10.2 million. The Company further claims that if production had commenced in 1984, the carried interest account would have been paid off in approximately two years and the Company would have begun to receive revenues from the field in 1986. At present, the Company does not expect to receive revenues before the year 2000, based on a price of Cdn. $1.28 per mcf and current production rates.

Columbia has filed a counterclaim against the Company seeking, if the Company is successful in its claim for the forfeiture of the field, repayment from the Company of all sums Columbia has expended on the Kotaneelee lands before the Company is entitled to its interest.

The parties to the litigation have conducted extensive discovery since the filing of the claims. The trial began on September 3, 1996 and the Company completed the presentation of its case against the Defendants on September 16, 1998. Based upon newly discovered evidence, the Company filed a new claim during May 1998 that the Defendants failed to develop the field in a timely manner. The Company is unable to estimate the time necessary to conclude the litigation.

Matters Ancillary to Kotaneelee Litigation

In its 1989 statement of claim, the Company sought a declaratory judgment regarding two issues:

(1) whether interest accrued on the carried interest account; and

(2) whether expenditures for gathering lines and dehydration equipment are expenditures chargeable to the carried interest account or whether the Company will be assessed a processing fee on gas throughput.

With respect to the first issue, the Company maintains that no interest should accrue on the account and the Defendants have not contested this position. With regard to the second issue, the Company maintains that the expenditures are chargeable to the carried interest account. Mobil, Esso and Columbia have essentially agreed to the Company's position while the Amoco Dome Group continues to contest this issue.

8. Litigation (Cont'd)

On January 22, 1996, the Company settled two claims outstanding against the Company in the Court of Queens Bench, Calgary, Alberta, which related to a suit brought against AlliedSignal Inc. ("AlliedSignal") in Florida which was dismissed on the basis that Canada was the appropriate forum for the litigation. AlliedSignal had sought additional relief against the Company in Canada to preclude other types of suits by the Company and to recover the costs of the defense of the initial action. The settlement bars AlliedSignal from making a claim against the Company for any costs in connection with the Kotaneelee Litigation. The Company agreed not to bring any action against AlliedSignal in connection with the Kotaneelee gas field. Neither party made any monetary payment to the other party.

In 1991, Anderson Exploration Ltd. acquired all of the shares in Columbia and changed its name to Anderson Oil & Gas Inc. ("Anderson"). Anderson is now the sole operator of the field and is a direct defendant in the Canadian lawsuit. Columbia's previous parent, The Columbia Gas System, Inc., which was reorganized in a bankruptcy proceeding in the United States, is contractually liable to Anderson in the legal proceedings currently at trial.

The working interest owners have reported that they have been selling Kotaneelee gas since February 1991.

Under Canadian law, certain costs (known as "taxable costs") of the litigation may be assessed against the non-prevailing party. Previously, the Company had reported that while such costs were not determinable, the Company estimated that taxable costs, assuming a twelve month trial, could be approximately $1.5 million and noted that the judge in complex and lengthy trials has the discretion to increase an award.

Effective September 1, 1998, the Alberta Rules of Court were amended to provide for a material increase in the costs which may be awarded to the prevailing party in matters before the Court. In addition, the Company believes that the trial will extend well beyond its original time estimates and, therefore, potentially assessable costs would increase accordingly.

8. Litigation (Cont'd)

The trial has been lengthy, complicated and costly to all parties and the Company believes that the prevailing party or parties in the litigation will argue for a substantial assessment of costs against the non-prevailing party or parties. The Court has very broad discretion as to whether to award costs and disbursements and as to the calculation of the amount to be awarded. Accordingly, the Company is unable to determine whether, in the event that it does not prevail on its claims in the litigation, costs will be assessed against it or in what amount. However, since the costs incurred by the Defendants have been substantial, and since the Court has broad discretion in the awarding of costs, an award to the Defendants potentially could be material. A cost award against the Company could be of sufficient magnitude to necessitate a sale of Company assets or a debt or equity financing to fund such an award. There are no assurances that any such sale or financing would be consummated.

There is no assurance whatever that the Company will be successful on the merits of its claims, which have been vigorously defended by the Defendants. There is also no assurance that the Company will be awarded any damages, or that, if damages are awarded, the Court will apply the measure of damages the Company claims should be applied.

9. Related party transactions

In 1991, the Company granted interests to certain of its officers, employees, directors, counsel and consultants amounting to an aggregate of 7.8% of any and all benefits to the Company after expenses from the litigation in Canada relating to the Kotaneelee gas field. The Company has reserved a 2.2% interest in such net benefits for possible future grants to persons who may include officers and directors of the Company.

Mr. Heath, a director of the Company, has royalty interests in certain of the Company's oil and gas properties, (present and past) which were received directly or indirectly through the Company. The Company and third-party operators and/or owners of properties made payments pursuant to these royalties for the benefit of Mr. Heath totaling U.S. $8,324, $11,158 and $10,844 in 1998, 1997 and 1996, respectively.

(Expressed in Canadian dollars)

10. Other financial information

Accrued liabilities

	1998	1997
Accrued accounting and legal expenses	$ 69,890	$137,650
Accrued royalties	141,575	139,645
Other	83,026	420
	$294,491	$277,715

	Year ended December 31,		
	1998	1997	1996
Royalty payments (1)	$146,161	$366,661	$147,572
Interest payments (2)	$ 1,625	$ 1,775	$ 2,224
Large corporation tax payments	$ 22,837	$ 27,388	$ 2,741

(1) Oil and gas sales are reported net of royalties paid.
(2) Bank line of credit charges.

11. Year 2000 date issue

The Year 2000 Issue arises because many computerized systems use two digits rather than four to identify a year. Date-sensitive systems may recognize the year 2000 as 1900 or some other date, resulting in errors when information using year 2000 dates is processed. In addition, similar problems may arise in some systems which use certain dates in 1999 to represent something other than a date. The effects of the Year 2000 Issue may be experienced before, on, or after January 1, 2000, and if not addressed, the impact on operations and financial reporting may range from minor errors to significant systems failure which could affect an entity's ability to conduct normal business operations. It is not possible to be certain that all aspects of the Year 2000 Issue affecting the Company, including those related to the efforts of customers, suppliers, or other third parties, will be fully resolved.

CANADA SOUTHERN PETROLEUM LTD.
SUPPLEMENTARY INFORMATION ON OIL AND GAS PRODUCING ACTIVITIES
(unaudited)

The following information includes estimates which are subject to rapid and unanticipated change. Therefore, these estimates may not accurately reflect future net income to the Company.

All amounts below except for costs, acreage, wells drilled and present activities relate to Canada. Oil and gas reserve data and the information relating to cash flows were provided by Paddock Lindstrom & Associates Ltd., independent consultants.

Estimated net quantities of proved oil and gas reserves:

	Oil (bbls)	Gas (bcf)
Proved reserves:		
December 31,1995	284,800	33.205
Revisions of previous estimates	178,448	(2.655)
Production*	(37,448)	(1.519)
December 31, 1996	425,800	29.031
Revisions of previous estimates	179,333	(3.802)
Production*	(71,333)	(.838)
December 31, 1997	533,800	24.391
Sale of properties	(350,800)	(2.632)
Revisions of previous estimates	(73,419)	(2.088)
Production*	(73,381)	(1.263)
December 31, 1998	36,200	18.408
Proved developed reserves:		
December 31, 1994	473,600	32.957
December 31, 1995	284,800	33.205
December 31, 1996	358,400	28.265
December 31, 1997	508,200	24.391
December 31, 1998	36,200	18.408

* Production data includes oil and gas sales and the proceeds from the carried interest properties.

Results of oil and gas operations:

	1998	1997	1996
Income:			
Oil and gas sales	$1,603,155	$1,644,222	$1,163,644
Proceeds under carried interest agreements	206,503	475,697	590,935
Gain on sale of assets	1,378,180	-	-
	3,187,838	2,119,919	1,754,579
Costs and expenses:			
Production costs	975,899	799,372	476,562
Depletion depreciation, and amortization	869,600	623,600	654,982
Provision for future site restoration costs	29,500	21,500	24,600
Abandonments and write downs	684,635	-	-
Income tax expense	-	-	-
	2,559,634	1,444,472	1,156,144
Net income from operations	$ 628,204	$ 675,447	$ 598,453

Capitalized costs of oil and gas activities:

	1998	1997	1996
Acquisition costs	$ 11,000	$ 399,000	$484,000
Exploration	174,000	546,000	146,000
Development	1,758,000	2,313,000	866,000

Standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities during the following period (in thousands of dollars):

	1998	1997	1996
Future cash inflows	$28,052	$46,435	$ 49,410
Future development and production costs	(14,030)	(22,517)	(20,813)
	14,022	23,918	28,597
Future income tax expense*	-	(1,573)	(2,931)
Future net cash flows	14,022	22,345	25,666
10% annual discount	(4,781)	(7,836)	(9,691)
Standardized measure of discounted future net cash flows	$ 9,241	$ 14,509	$ 15,975

* Reflects tax benefit for the years 1998, 1997 and 1996, from carryforward of exploration, development and lease acquisition costs, undepreciated capital costs and book earned depletion of $16,381,000, $18,065,000, and $17,032,000.

Current prices used in the foregoing estimates were based upon selling prices at the wellhead in the last month of each fiscal period. Current costs were based upon estimates made by consulting engineers at the end of each year.

Changes in the standardized measure during the following periods (in thousands of dollars):

	Year ended December 31,		
	1998	1997	1996
Changes due to:			
Sale of properties	$(4,374)	$ -	$ -
Prices and production costs	(402)	(579)	3,248
Future development costs	(1,204)	(2,350)	(1,049)
Sales net of production costs	(906)	(1,562)	(1,330)
Development costs incurred during the year	1,758	2,313	866
Net change due to extensions, discoveries and improved recovery	-	1,692	1,458
Revisions of quantity estimates	(872)	(3,642)	(4,229)
Accretion of discount	1,045	1,723	1,660
Net change in income taxes	(313)	939	423
Net change	$(5,268)	$(1,466)	$ 1,047

Item 9. **Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None.

PART III

For information concerning Item 10 – “Directors and Executive Officers of the Company,” Item 11 – “Executive Compensation,” Item 12 – “Security Ownership of Certain Beneficial Owners and Management” and Item 13 – “Certain Relationships and Related Transactions,” see the Proxy Statement of Canada Southern Petroleum Ltd. relative to the Annual Meeting of Shareholders for the fiscal year ended December 31, 1998, which will be filed with the Securities and Exchange Commission, which information is incorporated herein by reference. For information concerning Item 10 – “Executive Officers of the Company,” see Part I.

PART IV

Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) (1) Financial Statements

The financial statements and schedules listed below and included under Item 8, above are filed as part of this report.

(2) Consolidated Financial Statement Schedules

All schedules have been omitted since the required information is not present or not present in amounts sufficient to require submission of the schedule, or because the information required is included in the consolidated financial statements or the notes thereto.

(3) Exhibits

List of each management contract or compensatory or arrangement required to be filed as an exhibit pursuant to Item 14(c).

None.

(b) Reports on Form 8-K

On November 25, 1998, the Company filed a Current Report on Form 8-K to report that it had sold its heavy oil properties in Alberta for $2.2 million. In addition, the Company also reported that it completed the sale of its British Columbia properties for $3.6 million. The Company reported that it would record an estimated total gain of $1.3 million on the transactions.

(c) Exhibits

The following exhibits are filed as part of this report:

Item Number

2. Plan of acquisition, reorganization, arrangement, liquidation or succession

Not applicable.

3. Articles of Incorporation and By-Laws

(a) Memorandum of Association as amended on June 30, 1982, May 14, 1985 and April 7, 1988 filed as Exhibit 4B to Form S-8 as filed on November 25, 1998 is incorporated by reference.

(b) By-laws, as amended, filed as Exhibit 4C to Form S-8 as filed on November 25, 1998 are incorporated by reference.

4. Instruments defining the rights of security holders, including indentures

None.

9. Voting trust agreement

None.

10. Material contracts

(a) Agreements relating to Kotaneelee.

(1.) Copy of Agreement dated May 28, 1959 between the Company et al. and Home Oil Company Limited et al. and Signal Oil and Gas Company is filed herein.

(2.) Copies of Supplementary Documents to May 28, 1959 Agreement (see (1) above), dated June 24, 1959, consisting of Guarantee by Home Oil Company Limited and Pipeline Promotion Agreement, is filed herein.

(3.) Copy of Modification to Agreement dated May 28, 1959 (see (1) above), made as of January 31, 1961, is filed herein.

(4.) Copy of Agreement dated April 1, 1966 among the Company et al. and Dome Petroleum Limited et al. is filed herein.

(5.) Copy of Letter Agreement dated February 1, 1977 between the Company and Columbia Gas Development of Canada, Ltd. for operation of the Kotaneelee gas field is filed herein.

(b) Copy of Agreement dated January 28, 1972 between the Company and Panarctic Oils Ltd. for development of the offshore Arctic Islands gas fields is filed herein.

(c) Stock Option Plan adopted December 9, 1992 is filed herein.

(d) Stock Option Plan effective July 1, 1998 filed as Exhibit A to Schedule 14A Information (Proxy Statement) as filed on May 1, 1998 is incorporated by reference.

11. <u>Statement re computation of per share earnings</u>

None.

12. <u>Statement re computation of ratios</u>

None.

13. <u>Annual report to security holders, Form 10-Q or quarterly report to security holders</u>

Not applicable.

16. <u>Letter re change in certifying accountant</u>

Not applicable.

18. <u>Letter re change in accounting principles</u>

None.

21. <u>Subsidiaries of the Company</u>

Canpet Inc. incorporated in Delaware on August 3, 1973.
C. S. Petroleum Limited incorporated in Nova Scotia on December 15, 1981.

22. <u>Published report regarding matters submitted to vote of security holders</u>

None.

23. Consents of experts and counsel

(a) Paddock Lindstrom & Associates, Ltd. filed herein.
(b) Ernst & Young LLP filed herein.

24. Power of attorney

Not applicable.

27. Financial Data Schedule

Filed herein (EDGAR filing only).

99. Additional exhibits

(a) Statement of Claim filed on October 27, 1989 against Columbia Gas Development of Canada Ltd., Amoco Production Company, Dome Petroleum Limited, Amoco Canada Petroleum Company Ltd., Mobil Oil Canada Ltd. and Esso Resources of Canada Ltd. in the Court of Queen's Bench of Alberta Judicial District of Calgary, Alberta, Canada is filed herein.

(b) Amended Statement of Claim, amending the October 27, 1989 Statement of Claim, filed on March 12, 1990, is filed herein.

(c) Amended Statement of Claim in the same action, filed on November 17, 1993, is filed herein.

(d) Amended Statement of Third Party Notice by Amoco Canada Production Company Ltd. and Amoco Production Company, filed November 17, 1993 in the same action, is filed herein.

(e) Amended Statement of Defense to Third Party Notice by Anderson Oil & Gas Inc. (formerly Columbia Gas Development of Canada Ltd.) filed January 27, 1994 in the same action is filed herein.

(d) Financial Statement Schedules

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CANADA SOUTHERN PETROLEUM LTD.
(Registrant)

Dated: March 30, 1999

By /s/ M. Anthony Ashton
M. Anthony Ashton
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

By /s/ M. Anthony Ashton
M. Anthony Ashton
President and Director

Dated: March 30, 1999

By /s/ Kelly B. Johnson
Kelly B. Johnson
Treasurer and Chief Financial and Accounting Officer

Dated: March 30, 1999

By /s/ Benjamin W. Heath
Benjamin W. Heath
Director

Dated: March 30, 1999

By /s/ Timothy L. Largay
Timothy L. Largay
Director

Dated: March 30, 1999

By /s/ Arthur B. O'Donnell
Arthur B. O'Donnell
Director

Dated: March 30, 1999

By /s/ Eugene C. Pendery
Eugene C. Pendery
Director

Dated: March 30, 1999

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CANADA SOUTHERN PETROLEUM LTD.

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Calgary, Alberta

Benjamin W. Heath
President
Coastal Caribbean Oils & Minerals, Ltd.
Newport Beach, California

Timothy L. Largay
Partner
Murtha, Cullina, Richter and Pinney LLP
Hartford, Connecticut

Eugene C. Pendery
President
Recycled Plastic Products, Inc.
Denver, Colorado

Arthur B. O'Donnell
Consultant
West Hartford, Connecticut

OFFICERS

M. Anthony Ashton
President

Kelly B. Johnson
Secretary/Treasurer

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Calgary, Alberta T2P 3S8
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(403) 267-6555

CHARTERED ACCOUNTANTS

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1300 Ernst & Young House
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Calgary, Alberta T2P 3H6
CANADA

COMPANY WEB SITE
Financial results, corporate news and other company information are available on the Company's web site: **http://www.cansopet.com**

All shareholder correspondence relating to stock ownership or address changes, lost stock certificates, and other such matters should be directed to the Company's Transfer Agents in Canada or in the United States, as shown above. Other inquiries may be directed to Canada Southern's Executive Offices in Calgary, or, if more convenient, to the Company, c/o G&O'D INC, 149 Durham Road, Oak Park-Unit 31, Madison, Connecticut 06443. Telephone: (203) 245-7664. E-mail: gnod@connix.com.

The ticker symbol used on the Toronto, Boston and Pacific Exchanges is **CSW.**

The NASDAQ SmallCap Market uses the ticker symbol **CSPLF**.

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